(12) UK Patent Application (19) GB (11) 2 338 500 (13) A

(43) Date of A Publication 22.12.1999

(21) Application No 9921717.6

(22) Date of Filing 16.05.1996

Date Lodged 14.09.1999

(30) Priority Data
(31) 08447311 (32) 22.05.1995 (33) US

(62) Divided from Application No 9700460.0 under Section 15(4) of the Patents Act 1977

(51) INT CL[6]
E21B 33/134 33/127 33/13 33/14 43/10 43/12 43/14

(52) UK CL (Edition Q)
E1F FJT FJU FKA F204

(56) Documents Cited
None

(58) Field of Search
UK CL (Edition Q) E1F FJT FJU FKA
INT CL[6] E21B 33/127 33/13 33/134 33/14 43/10 43/12 43/14
EPODOC,WPI,JAPIO

(71) Applicant(s)
Baker Hughes Incorporated
(Incorporated in USA - Delaware)
3900 Essex Lane, Suite 1200, P.O.Box 4740, Houston, Texas 77210-4740, United States of America

(72) Inventor(s)
Richard Glenn Van Buskirk
Michael J Loughlin
Rustom K Mody
Albert A Mullins II
Michael H Johnson

(74) Agent and/or Address for Service
Boult Wade Tennant
27 Furnival Street, LONDON, EC4A 1PQ, United Kingdom

(54) Abstract Title
Method and apparatus for sealing and transferring force in a well bore

(57) A wellbore (1) is at least partially obstructed with a partition or obstruction member (5). A fluid slurry of an aggregate mixture of particulate matter is pumped into the wellbore adjacent the partition or obstruction member. The aggregate mixture of particulate material contains at least one component of particulate material, and each of the at least one particulate material components has an average discrete particle dimension different from that of the other particulate material components. Fluid pressure then is applied to the aggregate material, and fluid is drained from the aggregate material through a fluid drainage passage in the partition or obstruction member. The fluid pressure and drainage of fluid from the aggregate mixture combined to compact the aggregate mixture into a substantially solid, load-bearing, force-transferring, substantially fluid-impermeable plug member (11), which seals a first wellbore region from fluid flow communication with a second wellbore region. The plug member is easily removed from the wellbore by directing a high-pressure fluid stream toward the plug member, thereby dissolving or disintegrating the particulate material of the plug member into a fluid slurry, which may be circulated out of or suctioned from the wellbore. The invention is directed to the means whereby the particulate material is positioned.

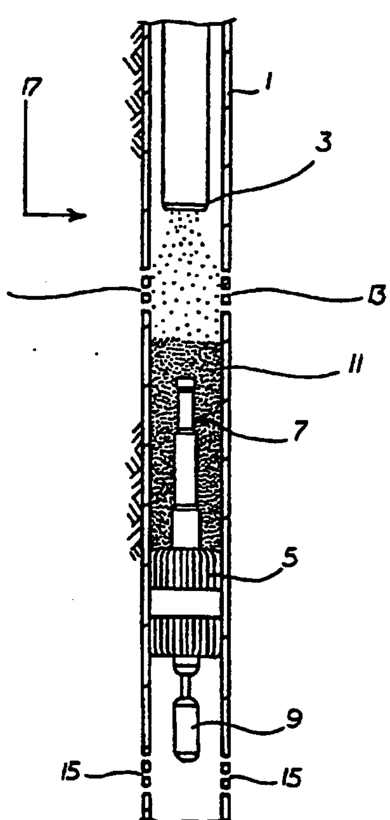


FIG. 1

GB 2 338 500 A

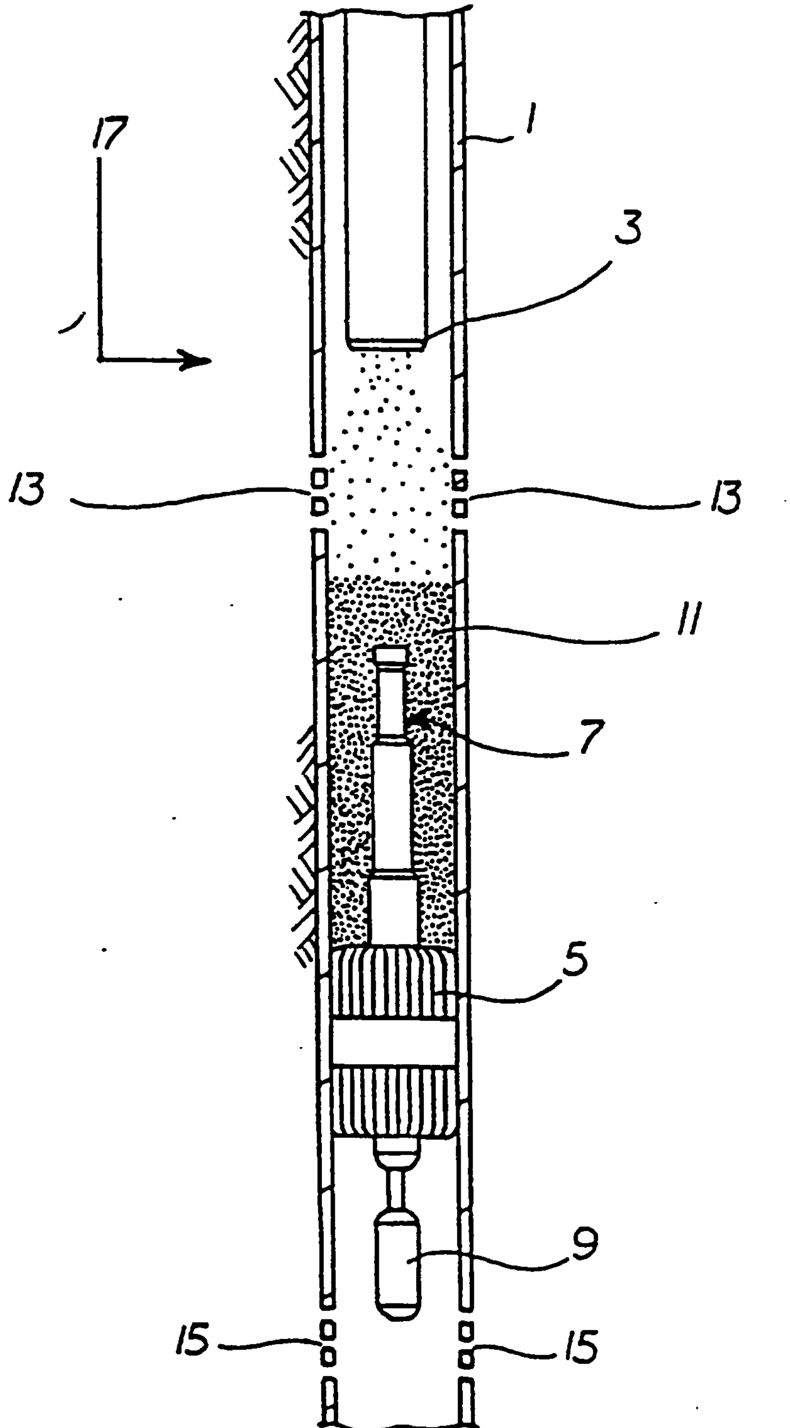


FIG. 1

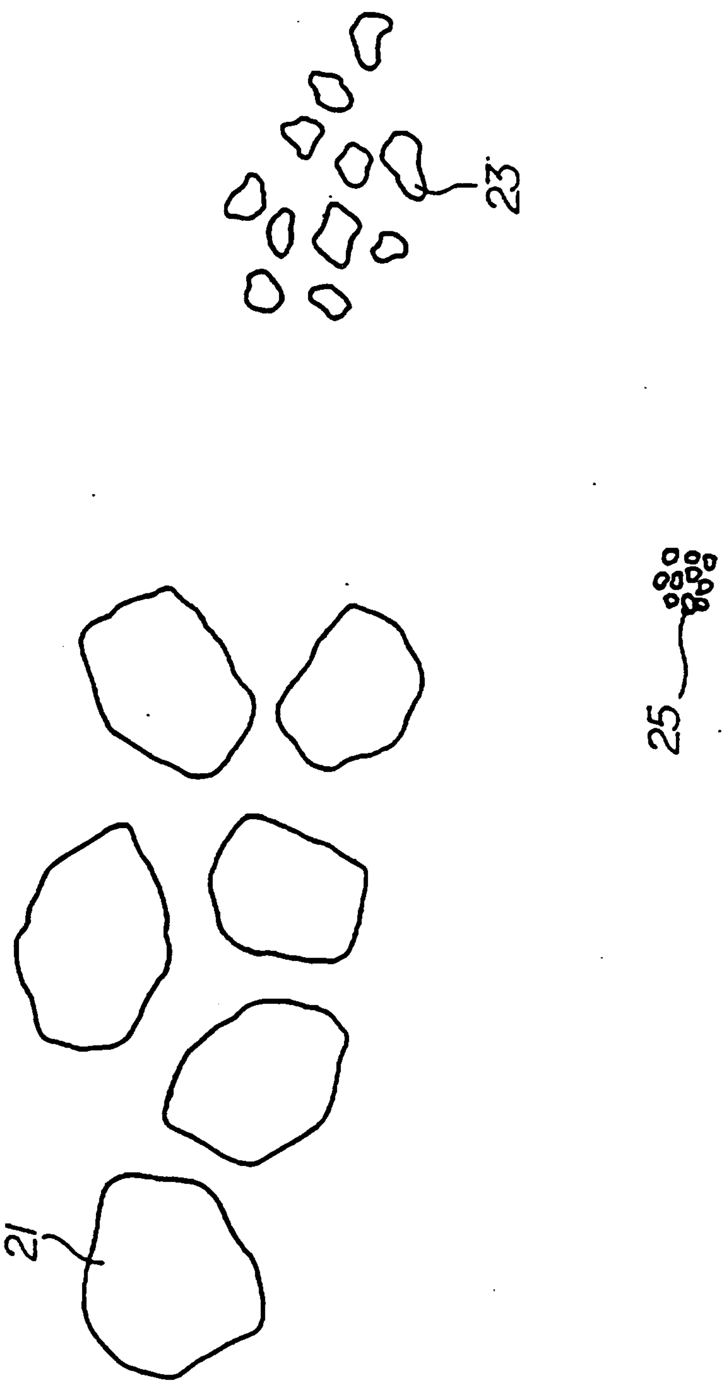


FIG. 2

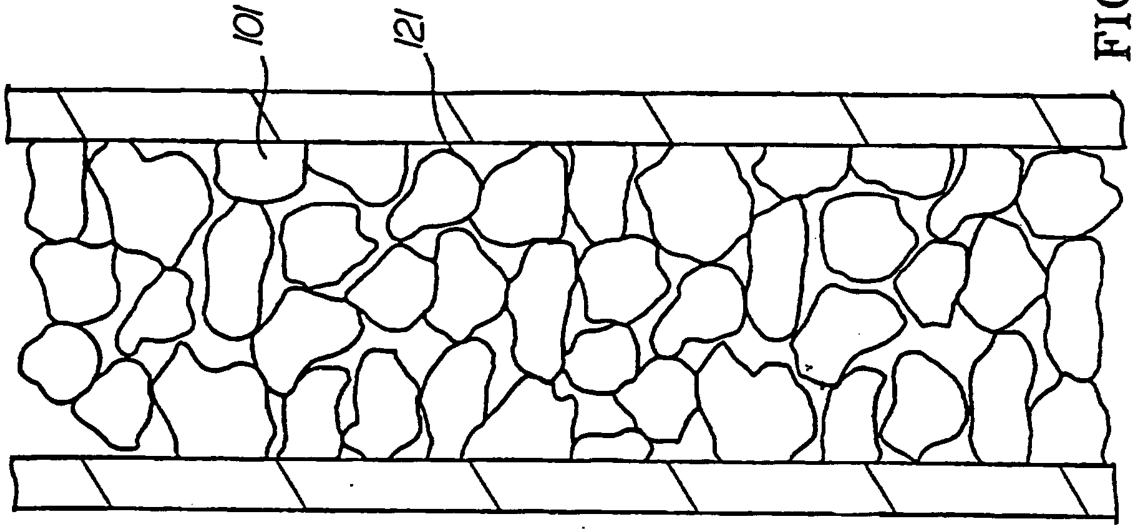


FIG. 3

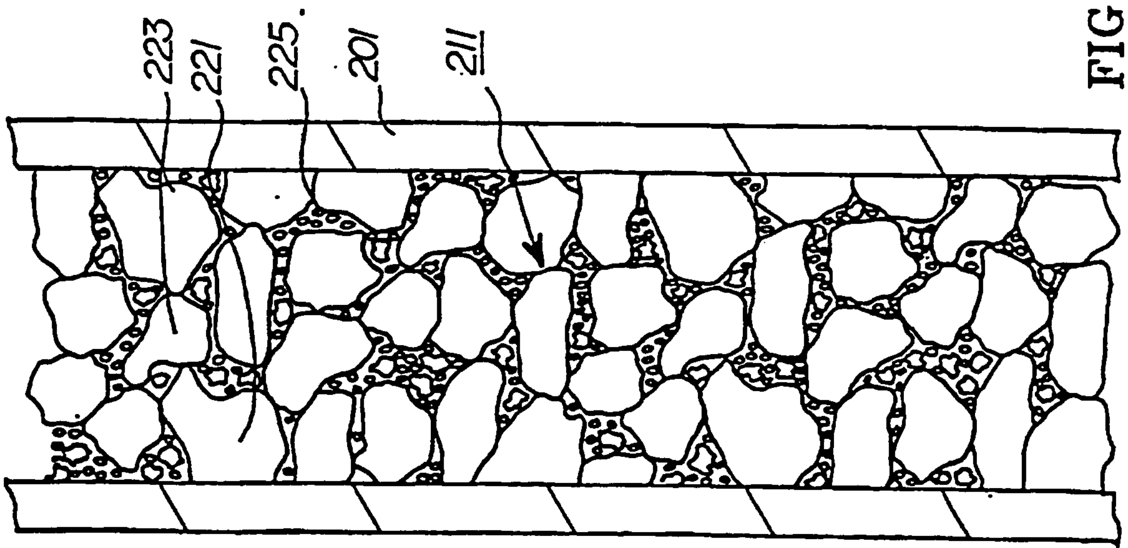


FIG. 4

TEST	MIXTURE A - B - C - D	MILLIDARCIES
1	00 - 00 - 00 - 00	2000.000
2	60 - 20 - 20 - 00	66.000
3	80 - 10 - 10 - 00	415.000
4	60 - 30 - 10 - 00	233.000
5	60 - 10 - 30 - 00	51.000
6	40 - 30 - 30 - 00	50.000
7	60 - 20 - 15 - 05	0.064
8	60 - 15 - 15 - 10	0.063
9	60 - 20 - 15 - 05	0.081

A = 20/40 MESH SAND
B = 100 MESH SAND
C = 200 MESH SAND
D = BENTONITE "GEL" (CLAY)

FIG. 5

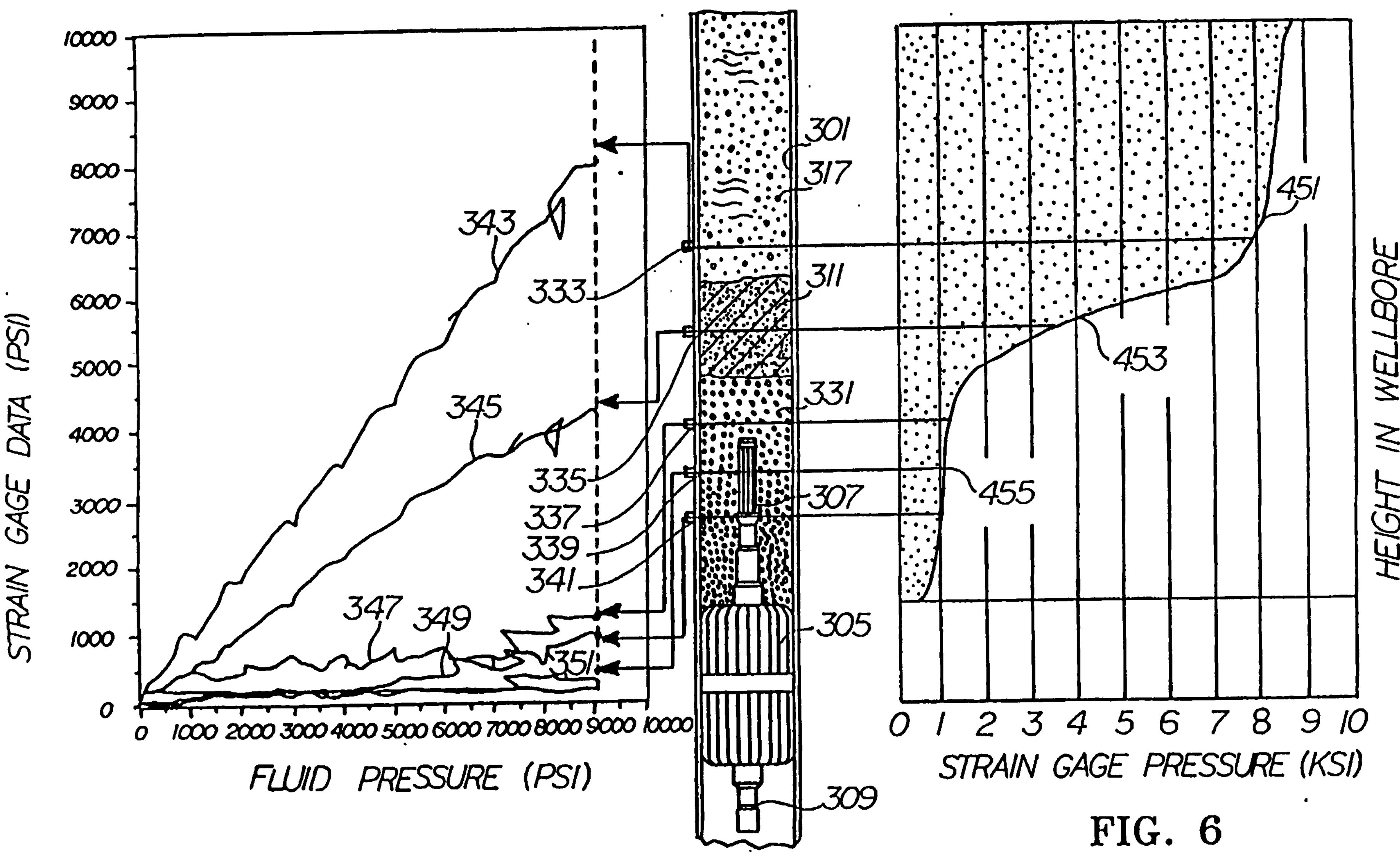
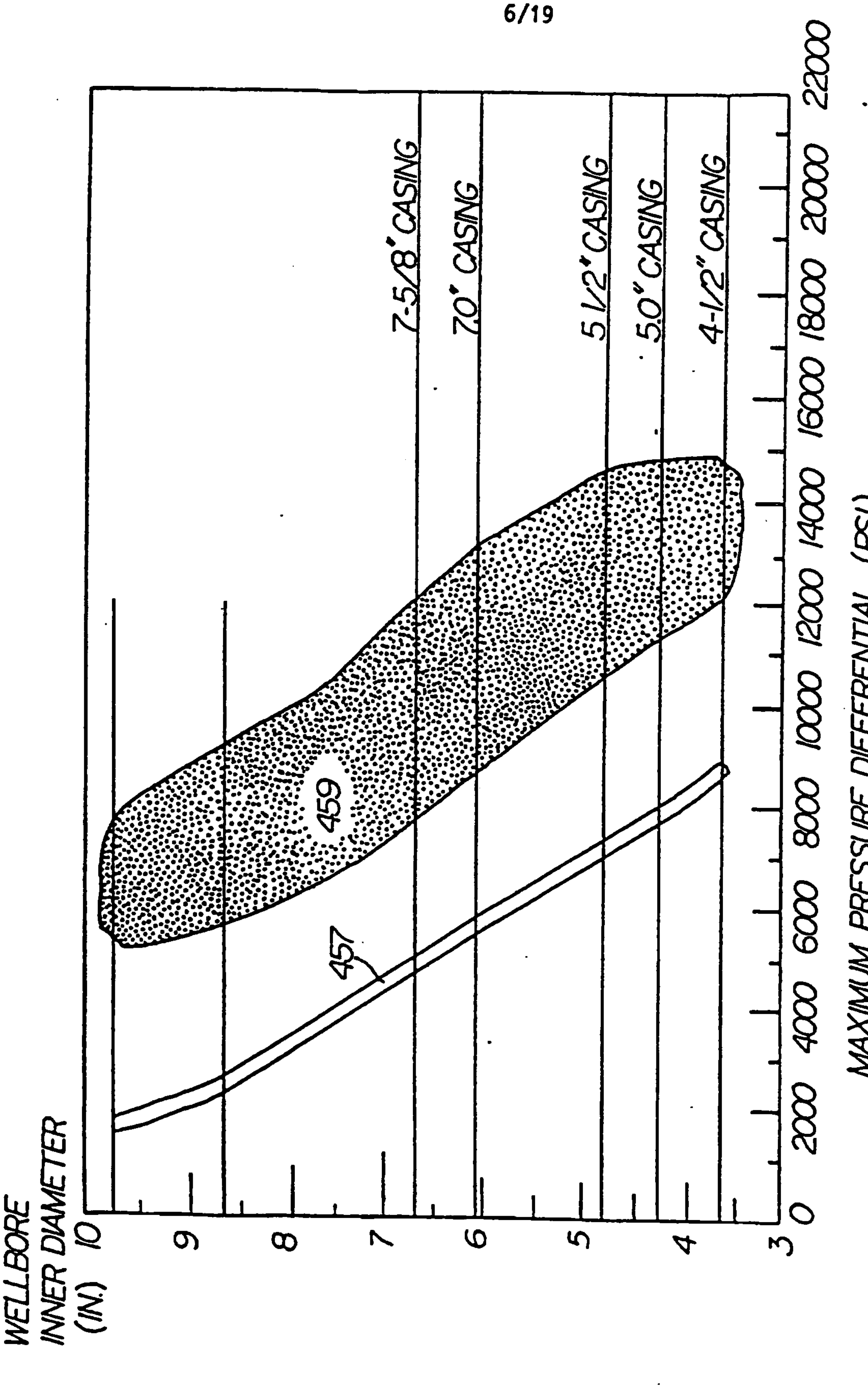

STRAIN GAGE DATA (PSI)
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
0 1000 2000 3000 4000 5000 6000 7000 8000 9000 10000
FLUID PRESSURE (PSI)
343
345
347
349
351
333
335
337
339
341
301
317
311
331
307
305
309
451
453
455
HEIGHT IN WELLBORE
0 1 2 3 4 5 6 7 8 9 10
STRAIN GAGE PRESSURE (KSI)

FIG. 6



WELLBORE
INNER DIAMETER
(IN.)
10
9
8
7
6
5
4
3
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
20000
22000
MAXIMUM PRESSURE DIFFERENTIAL (PSI)
7-5/8" CASING
7.0" CASING
5 1/2" CASING
5.0" CASING
4-1/2" CASING
457
459

FIG. 7

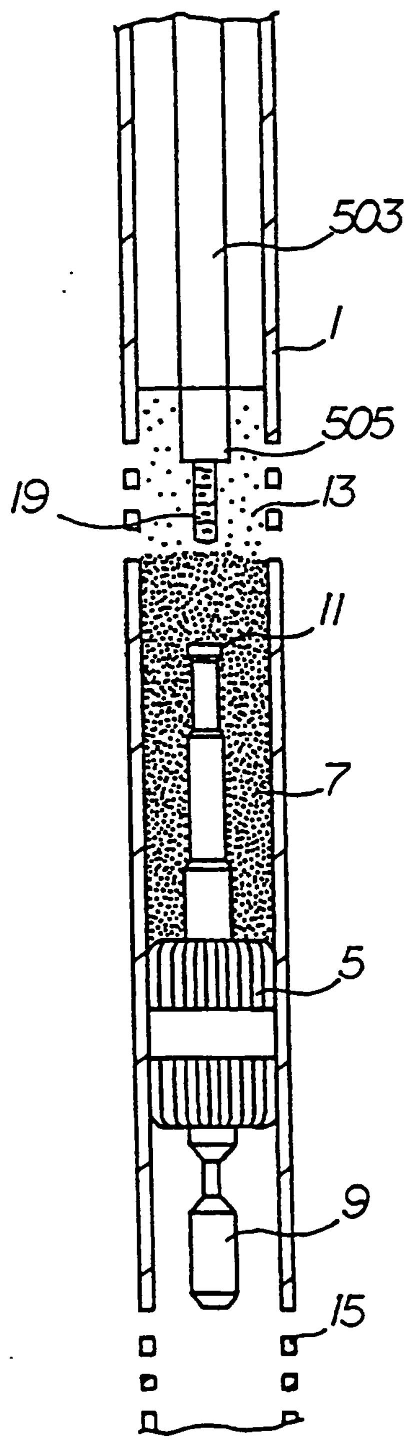


FIG. 8

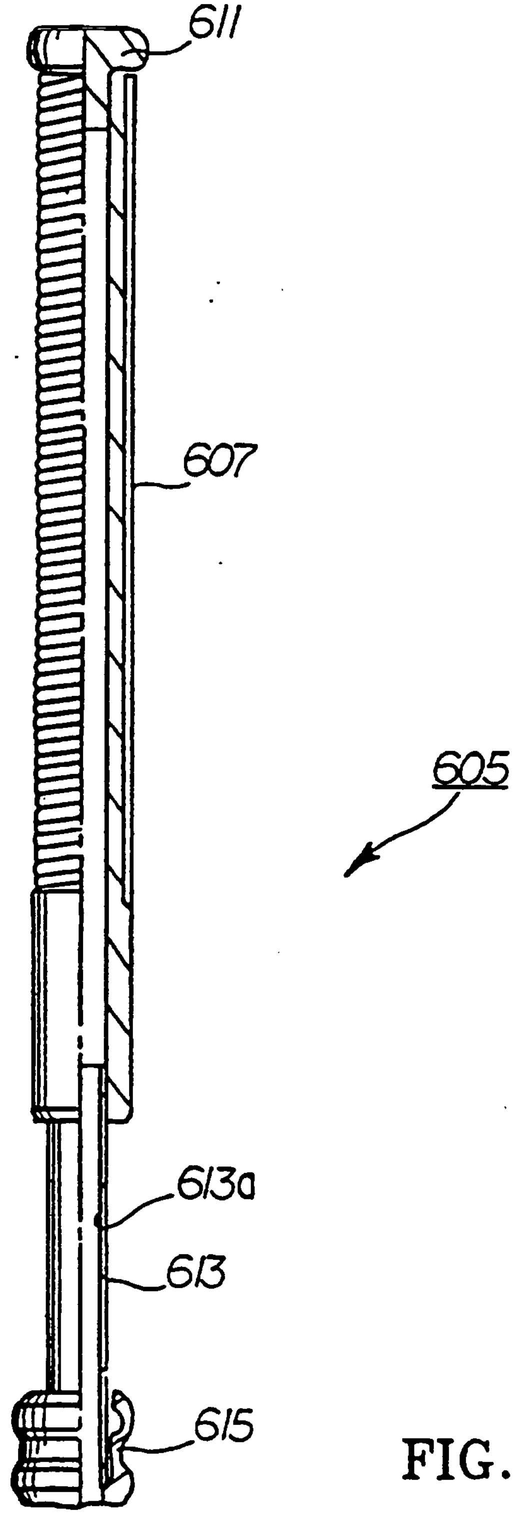


FIG. 9a

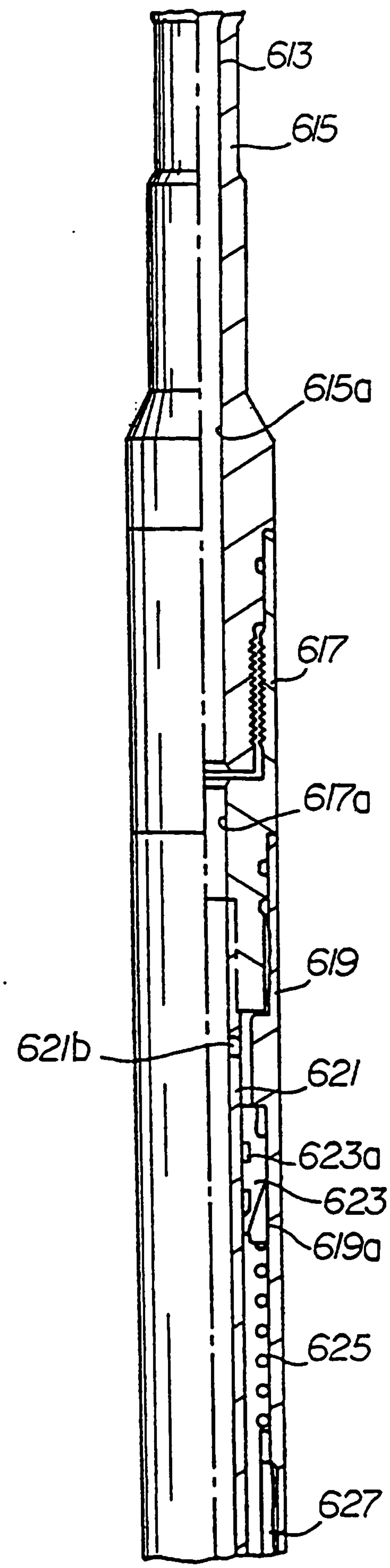


FIG. 9b

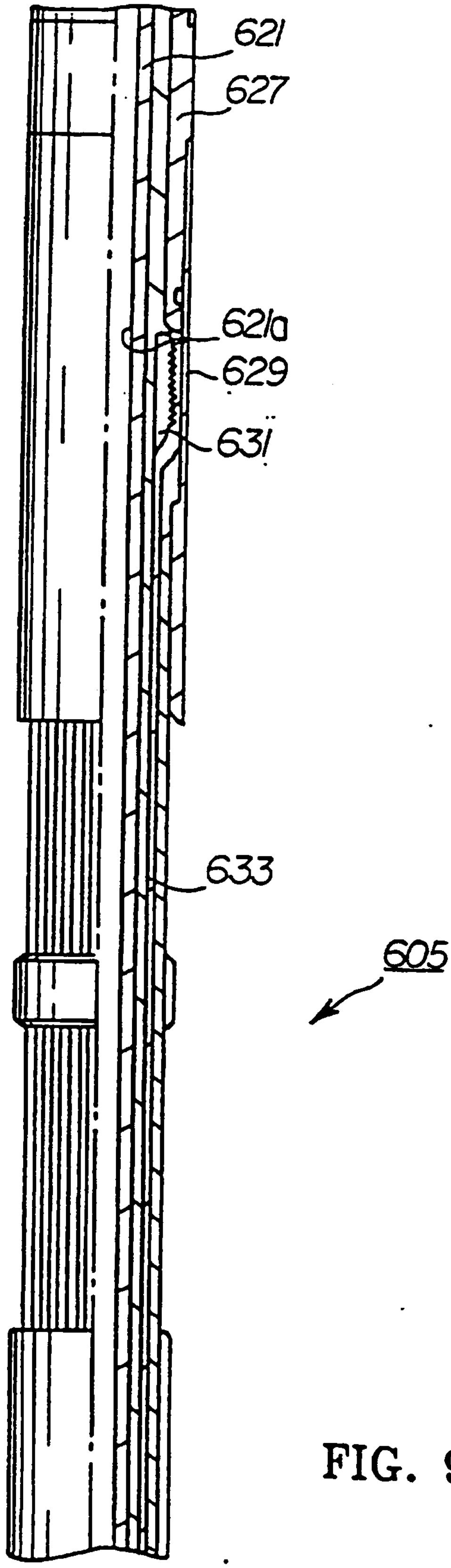


FIG. 9c

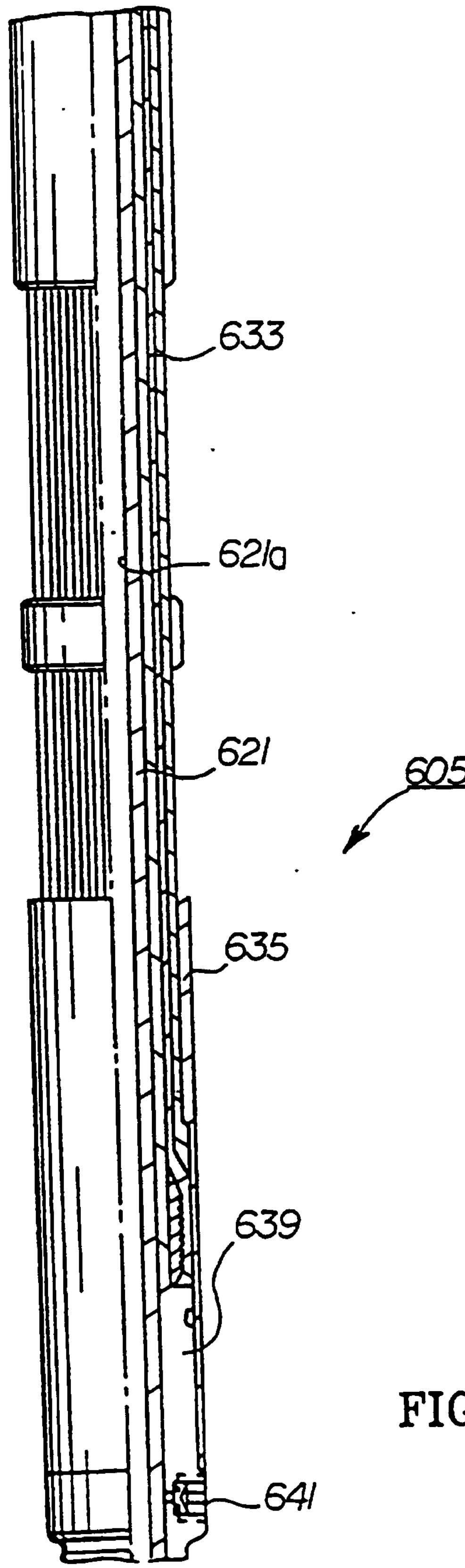


FIG. 9d

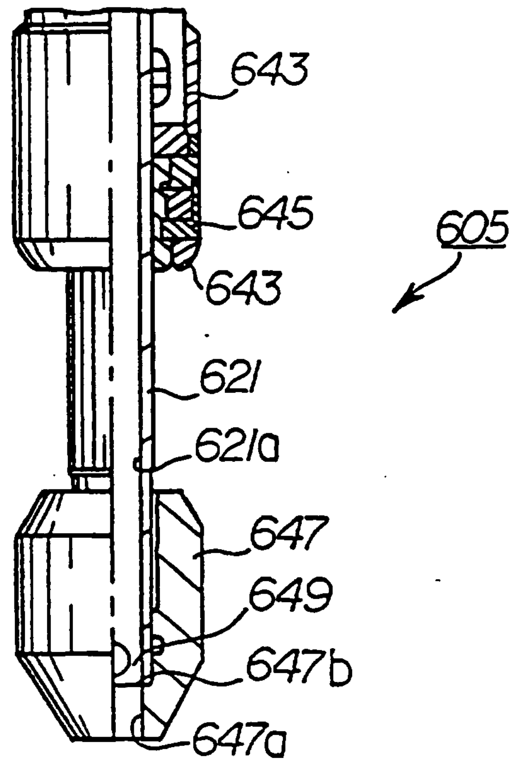


FIG. 9e

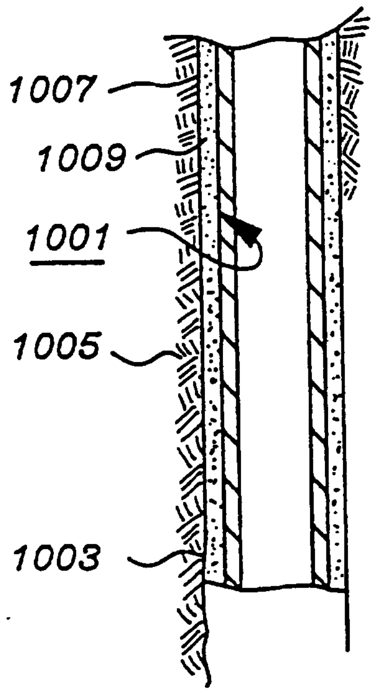


FIG. 10a

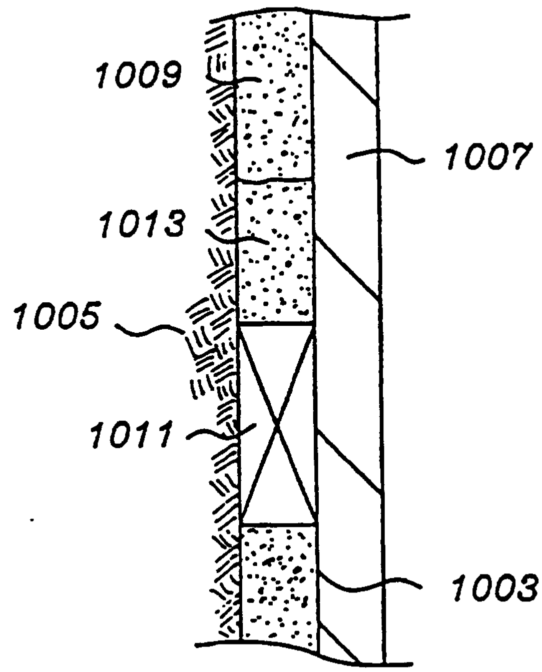


FIG. 10b

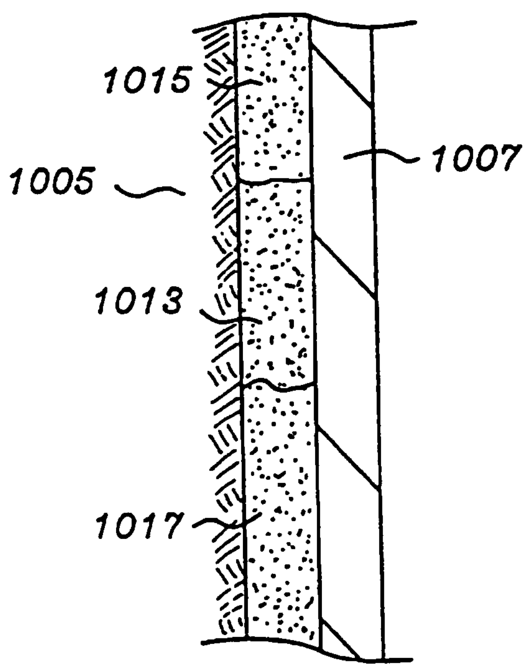


FIG. 10c

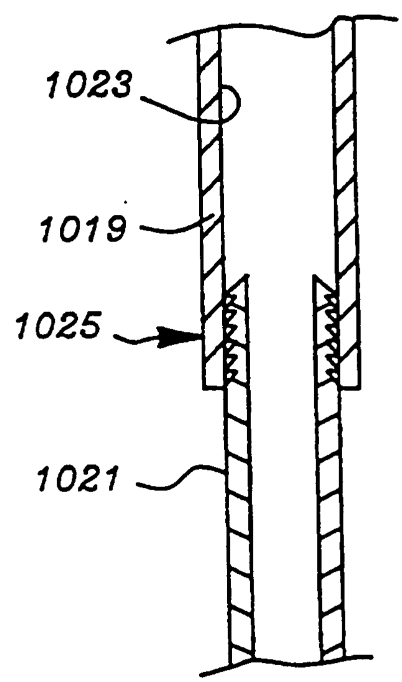


FIG. 10d

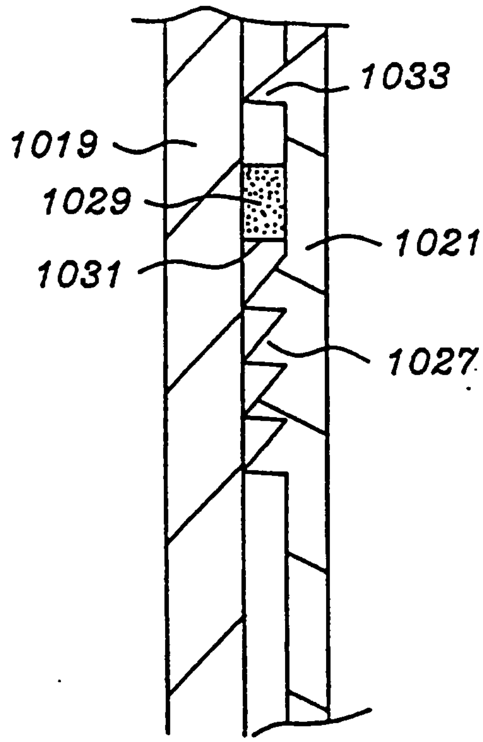


FIG. 10e

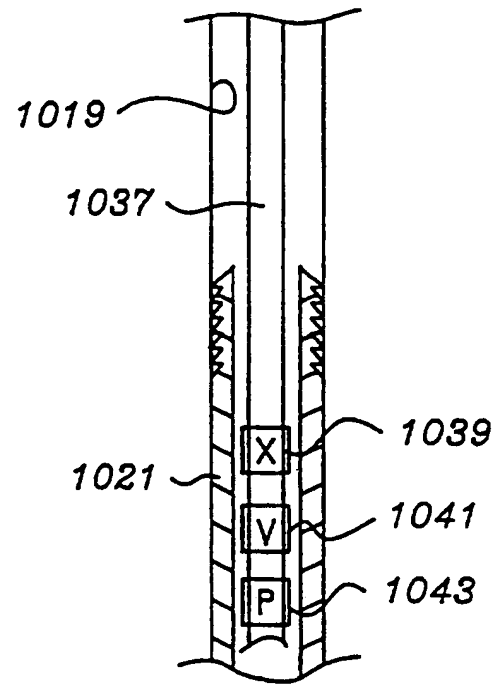


FIG. 10f

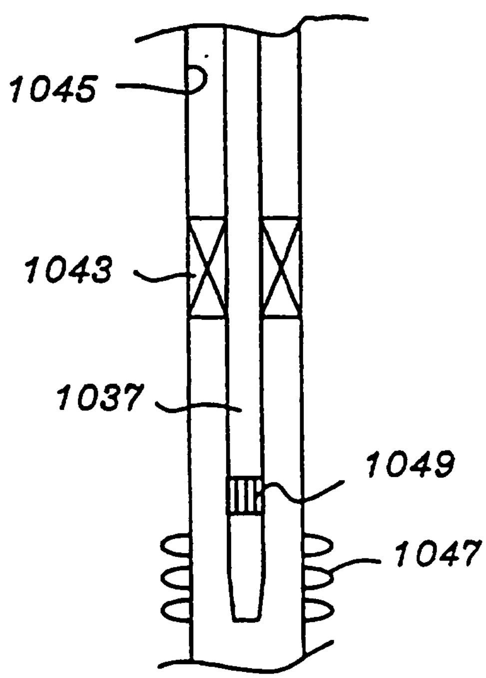


FIG. 10g

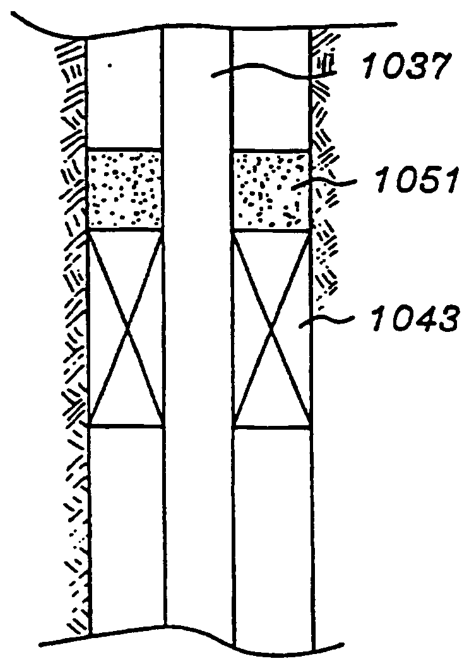


FIG. 10h

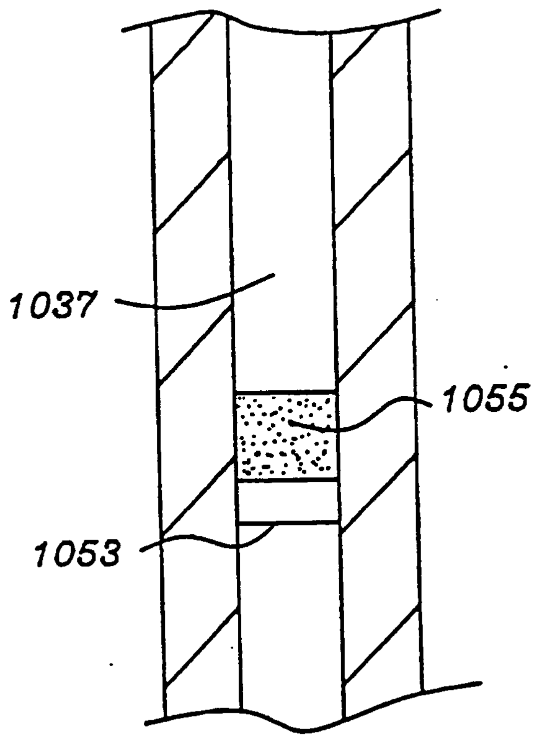


FIG. 10i

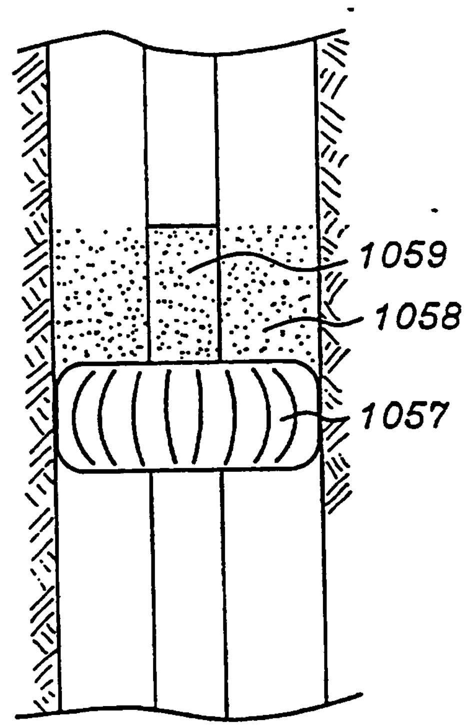


FIG. 10j

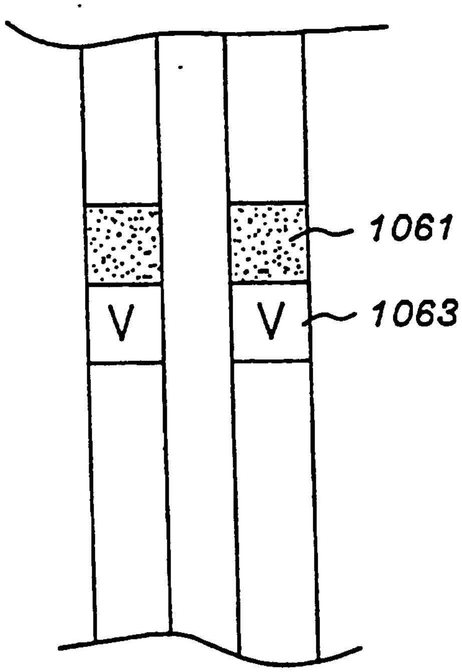


FIG. 10k

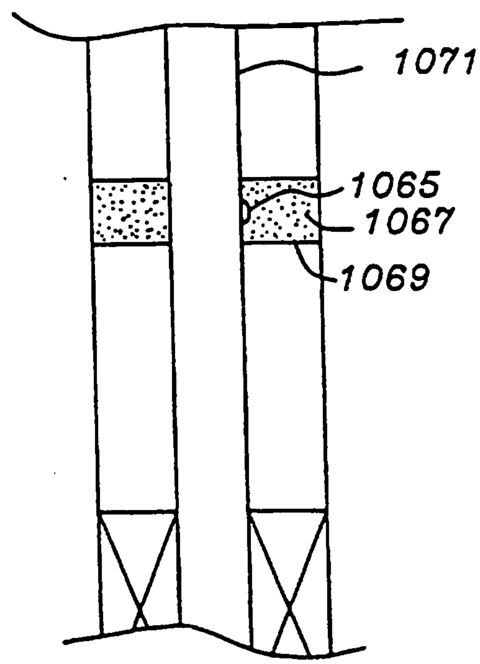


FIG. 10l

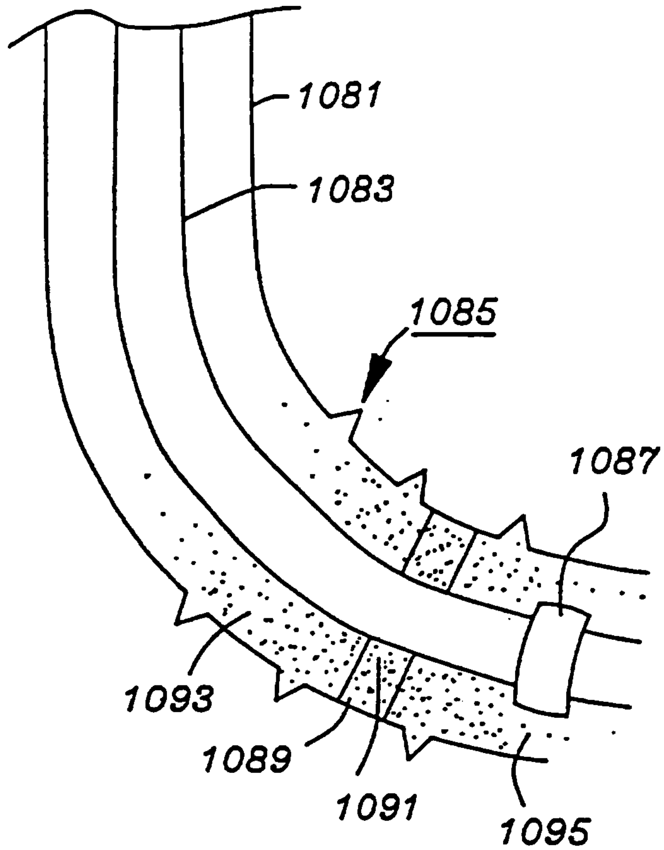


FIG. 10m

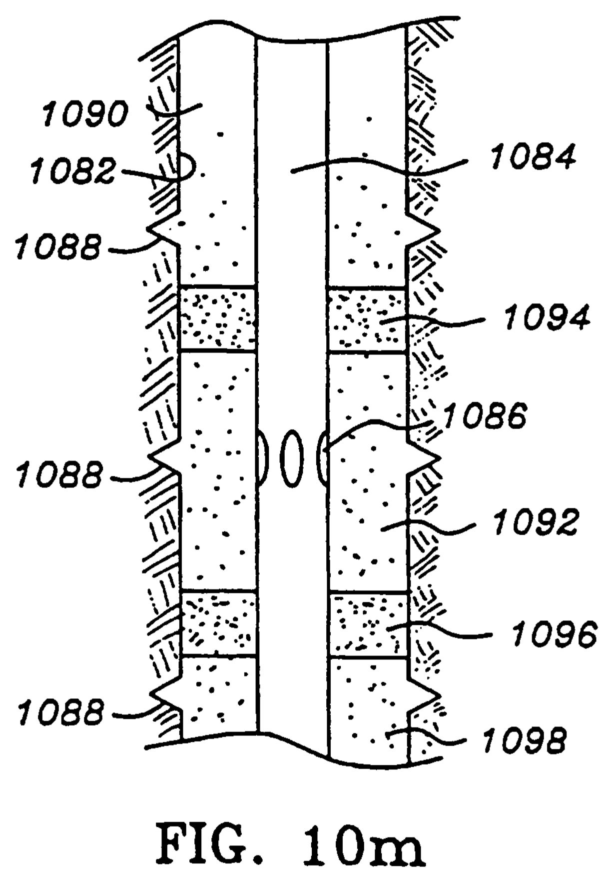


FIG. 10m

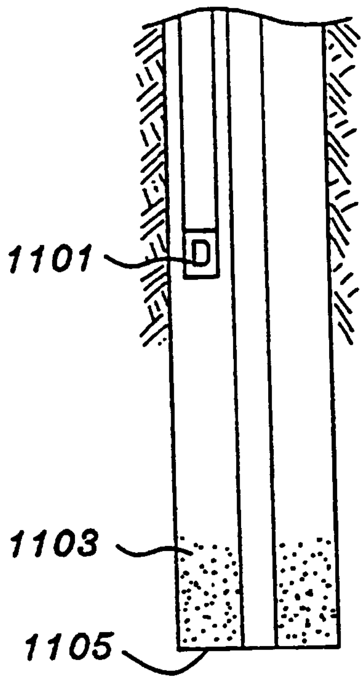


FIG. 11a

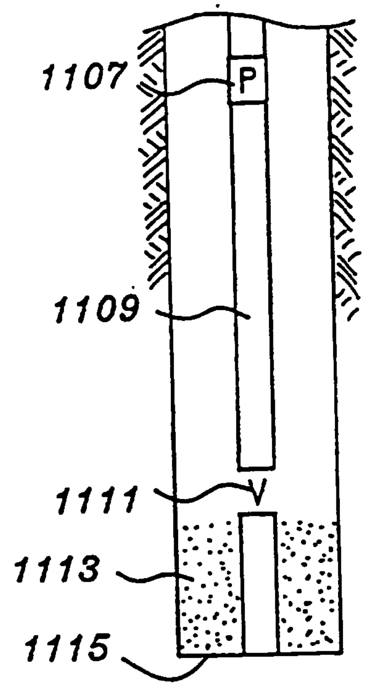


FIG. 11b

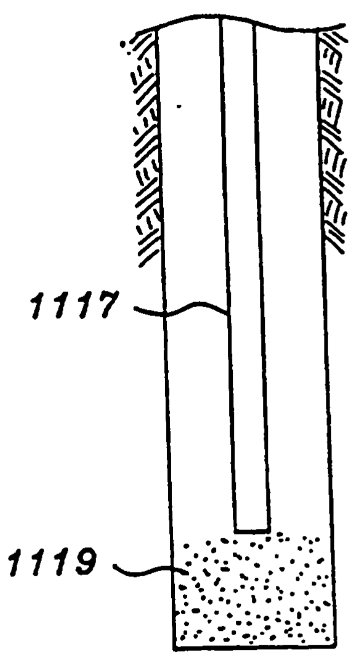


FIG. 11c

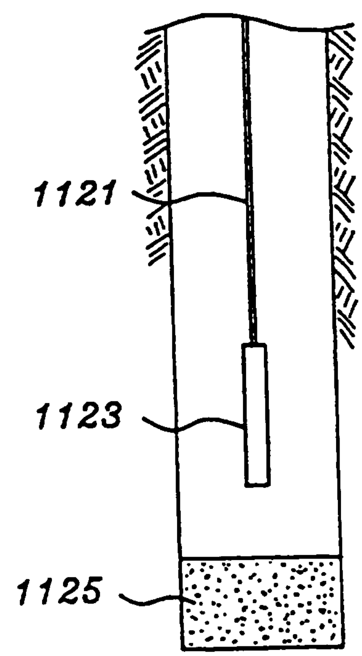


FIG. 11d

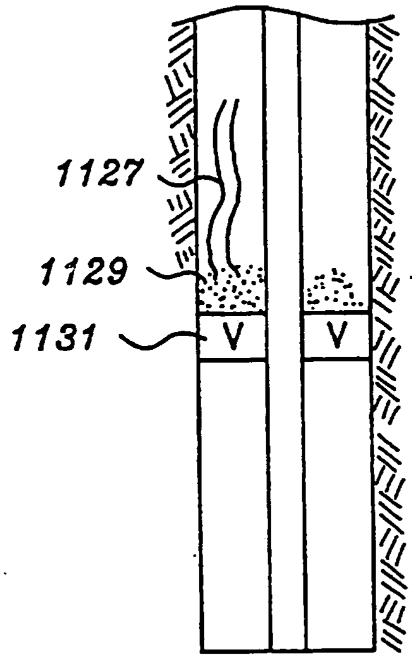


FIG. 11e

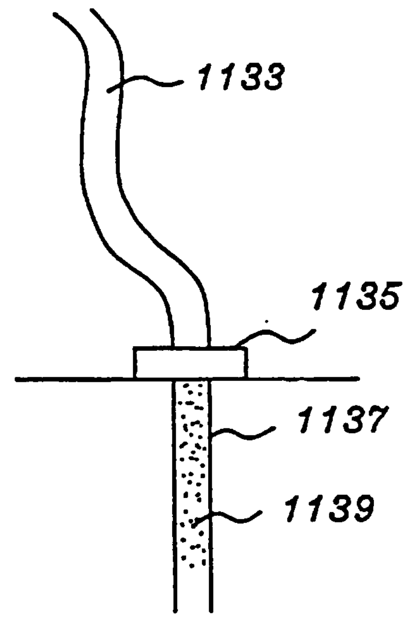


FIG. 11f

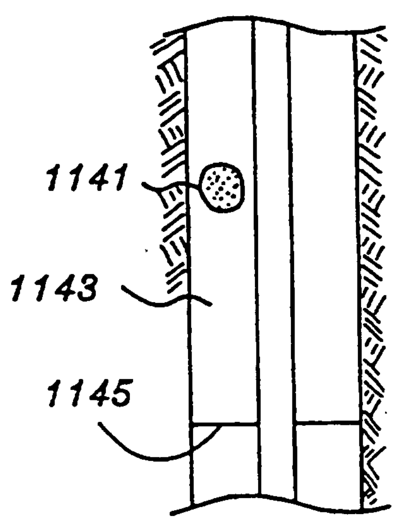


FIG. 11g

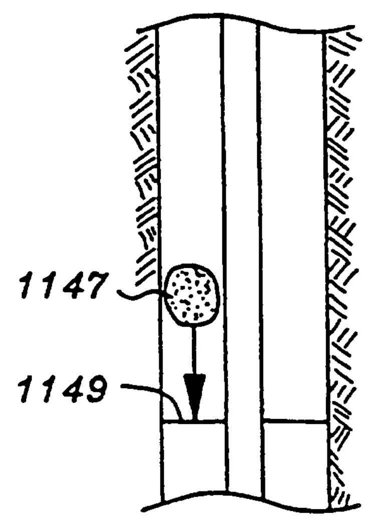


FIG. 11h

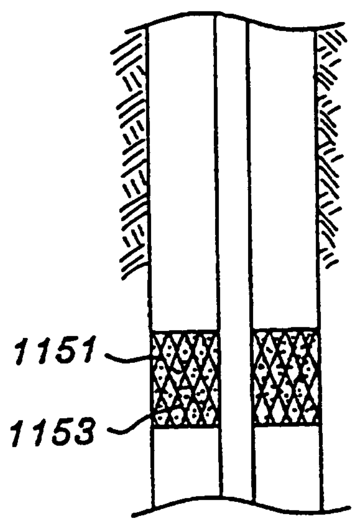


FIG. 11i

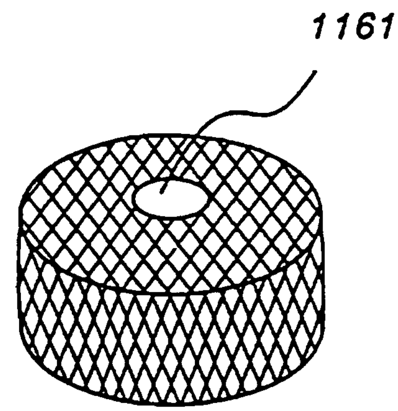


FIG. 11j

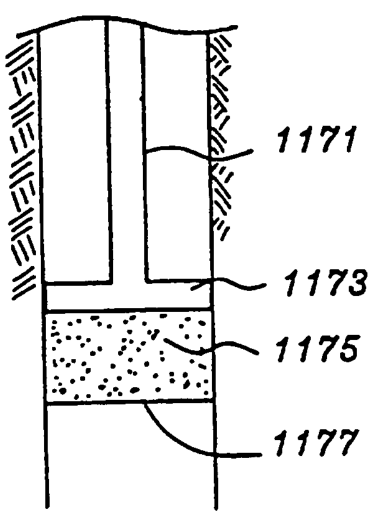


FIG. 11k

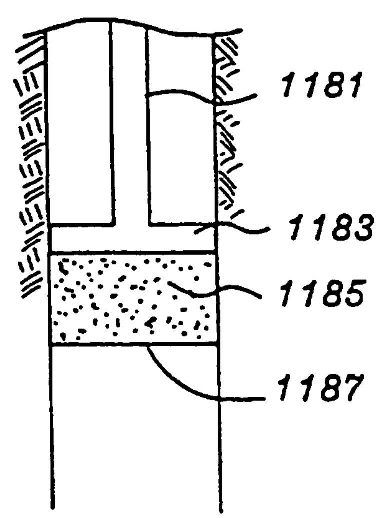


FIG. 11l

2338500

METHOD OF SEALING AND TRANSFERRING FORCE IN A WELLBORE

1. Field of the Invention:

The present invention relates generally to methods for forming downhole pressure plugs in a wellbore. More particularly, the present invention relates to methods of forming downhole plugs to seal the wellbore and to transfer stress from a wellbore tool to the wellbore itself. Additionally, the invention is directed to the use of particulate matter plugs to either transfer loads or to seal during completion operations.

2. Description of the Prior Art:

It is conventional in the oil and gas industry to seal wellbores using packers, bridge plugs, and the like. Typically, a wellbore tool, such as a packer or bridge plug, is run into the wellbore to a desired location therein. The packer or bridge plug is inflated or otherwise actuated into sealing engagement with the wellbore. Such a seal may be effected to separate regions in the wellbore, to contain fluid pressure either above or below the wellbore tool for fracturing or other well treatment operations, or other conventional reasons.

Conventional wellbore tools have a force threshold beyond which the wellbore tool will fail mechanically, or will lose gripping and sealing engagement with the wellbore, which tends to cause undesirable movement of the wellbore tool within the wellbore. The force threshold typically is defined in terms of a maximum or limiting differential pressure across the wellbore tool that the wellbore tool can withstand without failure or movement in the wellbore.

If the force threshold is exceeded, mechanical failure of the wellbore tool or undesirable movement of the wellbore tool may result. Mechanical failure may result in at least partial inoperability of the wellbore tool. If the wellbore tool is rendered inoperable, the wellbore may be undesirably obstructed, requiring expensive

fishing remedial operations. Mechanical failure at least will require expensive and time-consuming repair or replacement of the wellbore tool.

Even if the wellbore tool does not fail and is not otherwise damaged, the wellbore tool may be moved or displaced within the wellbore if the force threshold is exceeded. Such movement or displacement is undesirable because the positioning of the wellbore tool within the wellbore frequently is of great importance. Also, movement or displacement of the wellbore tool could damage other wellbore tools or the producing formation itself, thereby necessitating fishing, workover, or other remedial wellbore operations.

In secondary recovery operations, such as formation fracturing, reliable and dependable packers and bridge plugs frequently are necessary. Many secondary recovery operations require sealing off or packing a selected formation interval, and introducing extremely high pressure fluids into the selected interval. High-pressure fluids exert extreme axial forces on the packers or bridge plugs used to seal off the interval. Thus, the possibility of exceeding the force threshold of such wellbore tools is very great in formation fracturing, and requires the use of expensive, reinforced, high-pressure rated wellbore tools. High-pressure wellbore tools typically have relatively large cross-sectional diameters, precluding their use in through-tubing operations or operations in otherwise reduced-diameter or obstructed wellbores.

An alternative to high-pressure rated wellbore tools is to plug or seal the wellbore with cement. Cement plugs have a number of drawbacks. Expensive and specialized cementing equipment usually is required to pump cement into the wellbore to form a cement plug. Also, a significant time period must elapse to permit a cement plug to harden or set into a sealing or load-bearing cement plug. Another drawback of cement plugs is that they are relatively permanent, and require expensive and time-consuming milling operations to remove them from the wellbore.

During wellbore completion operations, a variety of wellbore tools are utilized to either transfer loads within the wellbore or to seal flow paths within the wellbore. For example, cement is utilized to secure sections of casing string in a fixed

position relative to the borehole. Alternatively, or in supplementation to casing cement, external casing packers are utilized to fix a section of casing in position relative to the borehole. Liner hangers are utilized to seal and couple. sections of casing string to one another. Typically, a casing section of radially-reduced dimension is suspended within a larger diameter casing string which is directly above. Generally, liner hangers include a gripping mechanism which allows the weight of the lower string to be transferred laterally to the upper string. Additionally, the liner hangers typically include metal-to-metal or elastomeric sealing elements or a combination of metal-to-metal and elastomeric sealing elements which seal the potential fluid flow path at the junction of the sections of casing strings.

A completion operation typically requires the placement of a tubing string in a concentric position relative to the casing string. Commonly, the tubing string is centralized and fixed in position relative to the casing string by one or more packer elements. Typically, the packers serve the dual purposes of transferring loads laterally and providing a seal in the annular region between the tubing string and the casing string. Also during completion operations, one or more sections of the casing string may be temporarily or permanently plugged to limit or prevent the flow of fluids between particular regions of the central bore of the tubing string.

In short, a large number of wellbore tools are utilized during completion operations to either transfer load within the wellbore or to provide a seal at a potential fluid flow path. These wellbore tools are generally rather expensive components. Additionally, they are difficult to replace and repair and frequently require the removal or all or a portion of the wellbore tubulars from the wellbore in order to allow workmen to replace a component. When, for example, a tubing string is pulled from a wellbore, the well is typically "killed"; that is, chemical additives are introduced into the well to prevent or limit the flow of hydrocarbons from the wellbore. Oil and gas well operators are generally reluctant to "kill" a well, since there is no guarantee that the well will later resume production at the levels of production prior to the "killing" and work over operations.

SUMMARY OF THE INVENTION

It is one objective of the present invention to provide a method of sealing a wellbore, wherein a first wellbore region is isolated from fluid communication with a second wellbore region.

It is another objective of the present invention to provide a method of forming a sealing plug member within a wellbore, wherein the plug member transfers force resulting from pressurized fluid in the wellbore to the wellbore itself, obviating the need for high-pressure rated wellbore sealing tools.

It is yet another objective of the present invention to provide a method of sealing a wellbore with a plug member that is both strong and substantially fluid-impermeable, yet is easily and quickly removable from the wellbore using conventional wellbore tools.

These and other objectives of the present invention are accomplished by at least partially obstructing a wellbore with a partition or obstruction member. A fluid slurry of an aggregate mixture of particulate matter is pumped into the wellbore adjacent the partition or obstruction member. The aggregate mixture of particulate material contains at least one component of particulate material, and each of the at least one particulate material components has an average discrete particle dimension different from that of the other particulate material components. Fluid pressure then is applied to the aggregate material and fluid is drained from the aggregate material through a fluid drainage passage in the partition or obstruction member. The fluid pressure and drainage of fluid from the aggregate mixture combined to compact the aggregate mixture into a substantially solid, load-bearing, force-transferring, substantially fluid-impermeable plug member, which seals a first wellbore region from fluid flow communication with a second wellbore region. The plug member is easily removed from the wellbore by directing a high-pressure fluid stream toward the plug member, thereby dissolving or disintegrating the particulate material of the plug member into a fluid slurry, which may be circulated out of or suctioned from the wellbore.

Preferably, the aggregate mixture of particulate matter contains a binder component comprising a finely dispersed particulate material which is capable of hydrating and swelling to fill pores or interstitial spaces between other particulate material components of the aggregate mixture of the plug member.

It is another objective of the present invention to utilize the particulate matter pressure plug in otherwise conventional completion operations in order to either transfer loads within the well or seal fluid flow paths within the well. In some applications, the particulate matter pressure plug may serve both functions simultaneously.

Other objects features and advantages of the present invention will become apparent to those skilled in the art with reference to the drawings and detailed description, which follow.

BRIEF DESCRIPTION OF THE DRAWINGS

The novel features believed characteristic of the invention are set forth in the appended claims. The invention itself, however, as well as a preferred mode of use, further objectives and advantages thereof, will best be understood by reference to the following detailed description of an illustrative embodiment when read in conjunction with the accompanying drawings. It should be noted that Figures 1 to 9 are included to provide a full explanation and to place the invention in context, but do not fall within the scope of the claims. In the drawings:

Figure 1 illustrates, in partial longitudinal section, a wellbore apparatus including a plug member;

Figure 2 schematically illustrates relative sizes of the particulate matter that makes up the aggregate mixture, which forms a plug member ;

Figure 3 schematically depicts a wellbore containing coarse sand particles;

Figure 4 illustrates a wellbore containing an aggregate mixture;

Figure 5 is a table illustrating the results of permeability tests performed on various mixtures and aggregate mixtures for use in forming a plug member ;

Figure 6 depicts a superimposition of a pair of graphs of data obtained during testing of a pressure plug or plug member ;

Figure 7 is a graph comparing the pressure rating of conventional high-pressure rated inflatable packers with the pressure rating of a plug member;

Figure 8 is a partial longitudinal section view of the sealing and load-bearing apparatus of **Figure 1**, the apparatus being shown in a plug member removal or washing-out mode of operation;

Figures 9a through **9e** should be read together and depict a one-quarter longitudinal section view of a partition or obstruction member;

Figures 10A through **10N** depict utilization of the particulate matter pressure plug of the present invention in otherwise conventional completion operations to either supplement or substitute for completion tools or completion methods; and

Figures 11A through **11L** depict alternative techniques for effecting conveyance, containment, and compaction of the particulate matter in order to form a particulate matter pressure plug in accordance with the present invention.

DETAILED DESCRIPTION OF THE INVENTION

Referring now to the figures, and specifically to Figure 1, wellbore apparatus will be described. **Figure 1** illustrates, in partial longitudinal section, a wellbore 1. Wellbore 1 is shown as a cased wellbore, but the apparatus is contemplated for use in open wellbores, production tubing, or the like, having conduit or a fluid passageway therethrough in which a pressure-tight seal may be advantageous. Wellbore 1 is provided with a source of axial force, in this case a workstring 3. In the case of workstring 3, the source of axial force is fluid pressure, but may be any other source of axial force. A removable partition or obstruction member 5 is disposed in wellbore 1. In this case, partition or obstruction member is an inflatable packer 5. However, the obstruction or partition member may be any sort of wellbore tool that is capable of selectively, and at least partially obstructing fluid flow from a first region of wellbore 1 with a second region. Inflatable packer 5 is provided at an upper extent with a screen filter assembly 7, and at a lower end with fluid outlet 9. The utility and function of screen filter 7 and fluid outlet 9 will be described hereinafter.

A pressure plug or plug member 11 is disposed adjacent to and above inflatable packer 5. Plug member 11 comprises a compacted aggregate mixture of particulate matter. Plug member 11 provides a substantially fluid-impermeable seal in wellbore 1, and thereby isolates a first region of wellbore 1 from fluid flow communication with a second region. Further, plug member 11 serves to transfer axial force from the source of axial force (in this case, fluid pressure from workstring 3) laterally to wellbore 1, thereby permitting use of a lower-pressure rated inflatable packer 5 or other obstruction or partition member.

The specific wellbore operation illustrated in Figure 1 is a secondary recovery operation, such as formation fracturing. Thus, wellbore 1 is provided with two sets of perforations 13, 15. Each set of perforations 13, 15 and the area defines a region in wellbore 1. In secondary recovery operations, it may be advantageous to isolate one set of perforations, in this case upper set 13, from another set of

perforations, in this case lower set 15, so that secondary recovery operations can be directed to only one formation through a single set of perforations 13. The secondary recovery operation illustrated in Figure 1 is known conventionally as fracturing the formation. In such a fracturing operation, wellbore 1 is packed-off, preferably with a plug member 7 according to the present invention. Workstring 3 then is run into wellbore 1, and fracturing fluid 17, which is conventional, is pumped into wellbore 1, out through perforations 13, and into the formation. Frequently, tremendous pressures are required to force fracturing fluid 17 into the formation. These fluid pressures may be exerted on wellbore 1, plug member 11, and inflatable packer 5. Such a fracturing operation, if employing only an inflatable packer 5 or other wellbore tool, would require inflatable packer 5 to withstand extreme differential pressure, and the resulting axial force, without mechanical failure or movement within wellbore 1. Accordingly, such high-pressure rated inflatable packers 5, as well as other high-pressure rated wellbore tools, are very expensive. Additionally, such wellbore tools generally are larger in diameter, which may preclude their use in through-tubing workover operations.

Plug member 11 is advantageous in that it provides a substantially fluid-impermeable seal in wellbore 1, and transfers axial force (caused in this case by fluid pressure from workstring 3) laterally to the wellbore and away from inflatable packer 5. Therefore, low-pressure rated inflatable packers 5, or other low-pressure rated wellbore tools, can be used in conjunction with plug member 11 and still maintain a substantially fluid-impermeable and strong seal in wellbore 1.

Figure 2 schematically illustrates the relative sizes of the classes of particulate matter that makes up the aggregate mixture that forms plug member 11. Preferably, the particulate matter is silica sand, or silicon dioxide. Sand particles 21 schematically represent grains of conventional, coarse 20/40 mesh, sand. The term "mesh" is conventional in the industry and represents an average discrete particle size for particulate materials, particularly sand. Recommended Practice Number 58, entitled "Recommend Practices for

Testing Sand Used in Gravel Packing Operations," published by the American Petroleum Institute, Dallas, Texas, is exemplary of the measurement of average discrete particle size of sands. Intermediate sand grains **23** schematically illustrate the size of 100 mesh silica sand, as contrasted to the size of coarse 20/40 mesh silica sand. Fine sand particles **25** schematically illustrate the relative size of 200 mesh sand particles, as contrasted to intermediate 100 mesh sand particles **23** and coarse 20/40 mesh sand particles **21**. An aggregate mixture of silica sand particles of various dimensional classes or mesh sizes is employed to form plug member **11**. The use of sand particles **21**, **23**, **25** of varying average discrete particle dimension is important to forming the substantially fluid-impermeable, force transferring plug member **11**.

Figure 3 schematically depicts a wellbore **101** containing coarse sand particles **121**. Coarse sand particles **121** are schematically depicted as particles of 20/40 mesh silica sand, as illustrated in **Figure 2**. As is illustrated, there are numerous pores and interstitial spaces between individual sand particles **121**. These pores or interstitial spaces permit the sand to be fluid-permeable, and also provide room for individual sand particles **121** to displace relative to each other in response to forces applied to the sand.

Figure 4 illustrates a wellbore **201** containing a plug member **211**. Plug member **211** comprises an aggregate mixture of coarse, 20/40 mesh sand particles **221**, intermediate, 100 mesh sand particles **223**, and fine, 200 mesh sand particles **225**. As is illustrated, the aggregate mixture of coarse, intermediate, and fine sand particles cooperate to reduce the volume of pores and interstitial spaces between the various sand particles **221**, **223**, **225**. Such an aggregate mixture results in a more substantially fluid-impermeable plug member **211**, and provides less space for individual sand grains to displace and move in response to forces exerted on plug member **211**.

Figure 5 is a table illustrating the results of permeability tests performed on various mixtures and aggregate mixtures for use in forming plug member **11**, **211**.

In the left hand column is a number assigned to each test performed. The central column indicates the volumetric or weight percentage of each component making up the aggregate mixture, wherein component A is 20/40 mesh silica sand (illustrated as **21** in **Figure 2**, **121** in **Figure 3**, and **221** in **Figure 4**), component B is 100 mesh silica sand (illustrated as **223** in **Figure 4**), component C is 200 mesh silica sand (illustrated as **225** in **Figure 4**), and component D is a bentonite or clay "gel." the right hand column indicates the measured or estimated fluid permeability of the mixture or aggregate mixture tested, in millidarcies. The Darcy is a unit of fluid permeability of materials, which is determined according to Darcy's law, which follows:

$$K = \frac{Q\mu L}{PA}$$

wherein, P = pressure across sand (in bars);

μ = dynamic viscosity of fluid (in centipoise);

A = cross-sectional area of sand (in square centimeters);

L = length of sand column (in centimeters);

Q = volume flow rate of effluent from sand column (in milliliters per second); and

K = permeability (in centimeters per second).

Accordingly, each aggregate sand mixture tested was formed into a column of known length L, and known cross-sectional area A. A fluid having a known dynamic viscosity μ, in this case water, was placed at one end of the sand column at a known pressure P. At an opposite end of the column, the flow rate of fluid effluent through the column Q was measured. The foregoing known and measured data was inserted into the above-identified mathematical statement of Darcy's law, and a permeability K was obtained in millidarcies. For test number one, a sand column of 100% 20/40 mesh sand was tested, and yielded an estimated permeability of 2,800 millidarcies. As a second test, an aggregate mixture containing 60% by volume 20/40 mesh sand, 20% by weight 100 mesh sand, and 20% by weight 200 mesh sand was tested, and yielded a permeability of 66 millidarcies. As a third test, an aggregate mixture of 80% by weight 20/40 mesh sand, 10% by weight, 100 mesh sand, and 10%

by weight 200 mesh sand was tested and yielded a permeability of 415 millidarcies. As a fourth test, an aggregate mixture of 60% by weight 20/40 mesh sand, 30% by weight 100 mesh sand, and 10% by weight 200 mesh sand was tested and yielded a permeability of 233 millidarcies. As a fifth test, an aggregate mixture of 60% by weight 20/40 mesh sand, 10% by weight 100 mesh sand, and 30% by weight 200 mesh sand was tested and yielded a permeability of 51 millidarcies. As a sixth test, an aggregate mixture of 40% by weight 20/40 mesh sand, 30% by weight 100 mesh sand, and 30% by weight 200 mesh sand was tested and yielded a permeability of 50 millidarcies.

Test numbers 7, 8 and 9 reflect aggregate mixtures that are preferred for use in forming plug member 11, 211. The aggregate mixtures tested in tests 7, 8 and 9 contain a fourth or binder component, five to ten percent by weight of bentonite. Bentonite is a rock deposit that contains quantities of a desirable clay mineral called montmorillonite. Montmorillonite is a colloidal material that disperses in fluid or water into individual, flat, plate-like clay crystals with dimensions ranging between about five and five hundred millimicrons. The flat plate-like clay crystals presumably overlap each other very tightly to produce a generally substantially fluid-impermeable structure. Additionally, montmorillonite crystals "hydrate" in water, wherein water molecules bond to the crystals, causing the crystals to swell to enlarged dimensions, which may further obstruct pores or interstitial spaces between coarser particles. Bentonite or bentonitic clays are interchangeable terms for any clay-like material possessing the properties discussed herein.

The addition of a binder of bentonite or bentonitic clay material to the aggregate mixtures described herein results in an aggregate mixture having an extremely low fluid permeability. It is believed that the microscopic nature of the clay particles, combined with their ability to hydrate and swell, permits the clay particles to fill and almost completely obstruct any pores or interstitial spaces remaining in an aggregate sand mixture (as illustrated in Figure 4). This theory is borne out by the test results in tests 7, 8, and 9. For test 7, an aggregate mixture of 60% by weight 20/40 mesh sand, 20% by weight 100 mesh sand, 15% by weight 200 mesh sand, and 5% by weight of bentonite material was tested and yielded a permeability of 0.064

millidarcies. For test number 8, an aggregate mixture of 60% by weight 20/40 mesh sand, 15% by weight 100 mesh sand, 10% by weight 200 mesh sand, and 15% by weight of bentonite material was tested, and yielded permeability of 0.063 millidarcies. For a ninth and final test, an aggregate mixture of 60% by weight 20/40 mesh sand, 20% by weight 100 mesh sand, 15% by weight 200 mesh sand, and 5% by weight bentonite material was tested and yielded a permeability of 0.081 millidarcies.

From the foregoing test results, trends indicating preferred compositions of aggregate mixtures for use in forming plug member 11, 211 can be noted. Marked decreases in fluid permeability are obtained by adding significant quantities of fine sand particles, such as 200 mesh sand, to a mixture containing coarse sand and intermediate sand components. A further reduction in permeability is obtained by adding ultra-fine, hydrating particles, such as bentonite or bentonitic clay materials.

Figure 6 depicts a superimposition of a pair of graphs of data obtained during testing of a pressure plug or plug member 311.

As illustrated in the central portion of Figure 6, the test rig comprises an artificial wellbore, in this case a length of casing 301, with a partition member, in this case an inflatable packer 305, disposed within wellbore 301. Inflatable packer 305 is further provided with a screen filter 307 at an uppermost end thereof, which is in fluid communication with a fluid exhaust member 309 at a lowermost extent of inflatable packer 305.

Adjacent and atop inflatable packer 305 is column of drainage sand 331 approximately 3 feet in height. Drainage sand 307 is a coarse, preferably 20/40 mesh, silica sand. Because the relatively coarse drainage sand 331 has a significant quantity of pores and interstitial spaces between individual sand particles, 307 will function as a pre-filter for fluid entering screen filter 307 of inflatable packer 305. Such a pre-filter is advantageous to prevent extremely fine particles from entering inflatable packer 305 and tending to cause abrasion and resulting failure of inflatable packer 305.

It is believed to be important to provide either a column of drainage sand, or to maximize the content (consistent with the desired level of fluid-impermeability) of relatively coarse (20/40 mesh silica sand) particles in the aggregate mixture so that drainage of plug members **11, 211, 311** is enhanced and to facilitate removal of plug member **11, 211, 311**, by washout. Without coarse particles, plug member **11, 211, 311** may compact into a rock-like member that cannot be removed easily.

A pressure plug or plug member **311** is formed atop drainage sand **331**. According to the preferred embodiment of the present invention, plug member **311** is a column of aggregate mixture as described herein that is twelve inches in height. The preferred aggregate mixture is that described with reference to test number 7 (60% by weight 20/40 mesh silica sand, 20% by weight 100 mesh silica sand, 15% by weight 200 mesh silica sand, and 5% by weight bentonite), having a measured fluid permeability of 0.064 millidarcies.

A quantity of pressurized fluid, in this case water **317**, is disposed in wellbore above plug member **311**. Pressurized fluid **317** serves as the source of axial force in the illustrated preferred embodiment. Pressurized fluid **317** exerts hydrostatic pressure both in a radial and an axial direction within wellbore **301**. Because wellbore **301** typically is extremely strong, and resistant to deformation, the axial force component, which otherwise would act directly on inflatable packer **305**, is the quantity of interest for purposes of the present invention.

Wellbore **301** is provided with a number of strain gauges **333, 335, 337, 339, 341**, which measure normalized hoop stress in wellbore **301**, thereby giving an indication of force transferred through plug member **311** to wellbore **301**.

During the test illustrated in Figure 6, pressurised fluid 317 was stepped-up in pressure in 703 x 10^3 kg m^2 (1,000 pounds per square inch (psi)) increments ranging from 0 to 6.3 x 10^6 kg m^2 (0 psi to 9,000 psi). The resulting strain gauge outputs, 343,345,347,349,351 and implicit force measurements, are plotted over the range of pressure increases in the left hand portion of **Figure 6**. The abscissa axis of the left hand graph plots the

magnitude of fluid pressure in pressurized fluid 317 in wellbore 301. The ordinate axis of the left hand graph plots hoop stress values measured by stain gauges 333, 335, 337, 339, 341. As is illustrated, strain gauge 333, which is located on an exterior of wellbore 301 at a point in which wellbore 301 is filled with pressurized fluid, shows the largest variation in measured hoop stress 343 as fluid pressure is increased. Strain gauge 335, which is located on the exterior of wellbore 301 where wellbore 301 is obstructed by plug member 311, indicates the second highest change in measured hoop stress 345. Stain gauge 337, which is located on the exterior of wellbore 301 at a point where wellbore 301 is filled with drainage sand 331, but above sand filter 307, measures a hoop stress 347 maximum of approximately 1,000 psi. Strain gauge 339, which is located on the exterior of wellbore 301 at a location where wellbore 301 is filled with drainage sand 331 and sand filter 307, measures a hoop stress 349 maximum of somewhat less than 703 x 10^3 kg/m^2 (1,000 psi). Strain gauge 341, which is located on the exterior of wellbore 301 wherein wellbore 301 is filled with drainage sand 331, and is just below screen filter 307 measures a hoop stress 351 maximum of less than 351 x 10^3 kg/m^2 (500 psi).

The right hand graph of Figure 6 depicts the pressure distribution over the length of wellbore 301, from areas filled by pressurized fluid 317 to the top of inflatable packer 305. The abscissa axis of the right hand graph plots measured hoop stress values, and is substantially similar to the ordinate axis of the left hand graph. The ordinate axis of the right hand graph corresponds with the height of wellbore 301 and correlates transfer of force from pressurized fluid 317 through plug member 311 and drainage sand 331, to wellbore 301. As is illustrated, upper right portion 451 of the plotted line is substantially vertical and reflects a relatively uniform pressure distribution in wellbore 301, which is to be expected because, at that point, wellbore 301 is filled with pressurized fluid 317, which exerts a generally uniform hydrostatic pressure on wellbore 301. A central portion 453 of the plotted line indicates a significant measured pressure drop in wellbore 301 where wellbore 301 is occupied by plug member 311. A lower left portion 455 of the plotted line indicates a fairly steady, maintained low pressure, which averages less than 703 x 10^3 kg/m^2 (1,000 psi) in wellbore 301. The significant pressure drop in wellbore 301 where it is occupied by plug member 311 indicates that the

axial force exerted by pressurized fluid **317** substantially is transferred by sand plug **311** to wellbore **301**. Thus, a relatively insignificant axial force load of generally less than 703×10^3 kg/m^2 (1,000 psi) is experienced by drainage sand and inflatable packer 305. Because such a large magnitude of axial force resulting from pressurised fluid 317 in wellbore **301** is transferred to the generally stronger wellbore **301**, much weaker and less expensive inflatable packers **305**, or other wellbore tools may be employed with plug member **311** to seal a first wellbore region against fluid flow to or from a second wellbore region.

Figure 7 is a graph comparing the pressure rating of conventional high-pressure rated inflatable packers (such as **305** in **Figure 6**) with the pressure rating of plug member **11**, **211**, **311**. The abscissa axis of the graph plots the values of limiting differential pressure of failure threshold that each type of sealing member can withstand and maintain effective sealing integrity. The ordinate axis plots the casing inner diameter of the wellbore to be sealed. Plotted line **457** represents the pressure rating of a high-pressure rated, 8.6cm (3 3/8") outer diameter inflatable packing element. The ability of the packing element to withstand pressure differentials (limiting differential pressure in **Figure 7**) is a function of the diameter of the casing or wellbore that the inflatable packer must seal. For small diameter casing, such as 11.4cm (4½") casing, the limiting differential pressure or failure threshold is relatively high at approximately 6.3×10^6 kg/m^2 (9,000 psi). However, as the casing or wellbore diameter increases, the inflatable packer must expand further to sealingly engage the casing inner diameter, thus reducing the pressure differential (limiting differential pressure) that it is capable of withstanding. Therefore, for a large diameter casing, such as 27.3cm (10¾") diameter casing, the inflatable packer can only withstand a pressure differential (limiting differential pressure) of approximately 1.4×10^6 kg/m^2 (2,000 psi). In contrast, the pressure rating of a plug member **11**, **211**, **311**, is much higher, and is less sensitive to casing diameter than are conventional inflatable packing elements. Area 459 of Figure 7 represents the pressure rating of plug members 11, 211, 311 formed according to the present invention, as predicted by tests conducted substantially as described with reference to **Figure 6**. As is illustrated, in relatively small diameter casing, plug members **11**, **211**, **311** can withstand pressure differentials (limiting differential pressure) of upwards of

9.8×10^6 kg/m^2 (14,000 psi). In larger diameter casing, plug members 11, 211, 311 formed according to the present invention can withstand pressure differentials (limiting differential pressure) of upwards of 3.5×10^6 kg/m^2 (5,000 psi). From the data depicted in Figure 7, it becomes apparent that plug members 11, 211, 311 possess significant advantages over conventional inflatable packer elements and other wellbore tools.

Figure 8 is a partial longitudinal section view of the sealing and load-bearing apparatus of Figure 1, the apparatus being shown in a plug member 11 removal or washing-out mode of operation. As in Figure 1, wellbore 1 has removable partition or obstruction member 5, including screen filter member 7 and fluid exhaust member 9, and plug member 11 disposed therein. Original fracturing workstring 3 is replaced by a circulating or washout workstring 503. Circulating or washout workstring 503 is provided with a nozzle at a terminal end thereof for directing a high-pressure fluid stream 19 toward plug member 11. High pressure fluid stream 19 is provided to dissolve or wash out plug member 11. As is illustrated, the impact of high pressure fluid stream 19 upon plug member 11 causes the particulate matter of plug member 11 to separate into discrete particles. Relatively slow-moving wellbore fluid suspends the particles of particulate matter so that the particulate matter and wellbore fluid 505 may be circulated out of or suctioned from wellbore 1. After plug member 11 is fully disintegrated, inflatable packer member 5 may be conventionally deflated and retrieved. Therefore, plug member 11 while stronger and capable of bearing more load with excellent sealing integrity, is simply and easily removed from wellbore 1 when its presence is no longer desirable.

Figures 9a through 9e, which should be read together, depict in one-quarter longitudinal section, a partition or obstruction member, in this case an inflatable bridge plug 605. A screen filter 607 is provided at an uppermost end of bridge plug 605. Screen filter 607 is plugged at its upper end with plug member 611. A connection tube 613 connects a lower extent of screen filter 607 in fluid communication with fishing neck 615. Fishing neck 615 is provided with a fluid flow conduit 615a therethrough for fluid communication with

upper element adapter **617**. Upper element adapter **617** is connected by threads to fishing neck **615**, and is provided with a fluid conduit **617a** therethrough and is connected by threads to poppet housing **619**.

A mandrel **621** is connected by threads to upper element adapter **617**. Mandrel **621** is provided with a fluid conduit **621a** therethrough, and also includes a fluid port **621b**. A poppet **623** is disposed between an exterior of mandrel **621** and an interior of poppet housing **619**. Poppet **623** is further provided with a pair of seal members **623a**. Poppet is biased upwardly by a biasing member or spring **625**.

An element adapter **627** is connected by threads to poppet housing **619**. Element adapter **627** is connected by threads to an upper element ring **629**. Upper element ring **629** cooperates with upper wedge ring **631** to secure a conventional inflatable packer element **633** to element ring **629**. Inflatable packer element **633** is conventionally constructed of elastomeric materials and a plurality of circumferentially overlapping flexible metal strips.

A lower element ring **635** is secured to inflatable packing element **633** by lower wedge ring **637**. Lower element ring **629** is connected by threads to a lower element adapter **639**. Lower element adapter **639** is provided with a threaded bleed port **641**, which is selectively opened and closed to bleed air from between mandrel **621** and inflatable packing element **633** during assembly of bridge plug **605**. Lower adapter **639** is connected by threads to a lower housing **643**. Lower housing **463** is secured to mandrel **621** by means of a shear member **645**, which permits relative motion between lower housing **643** and mandrel **621** upon application of a force sufficient to fail shear member **645**.

A guide shoe **647** is connected by threads to mandrel **621**, and is provided with a fluid conduit **647a** in fluid communication with fluid conduit **621a** of mandrel **621**. Guide shoe **647** is further provided with a closure member, in this case a ball seat **647b**, which is adapted to receive a ball **649** to selectively obstruct fluid flow through inflatable bridge plug **605**. Preferably, ball seat **647b** is a pump-through

ball seat, which will release ball 649 and permit fluid flow out of bridge plug 605 upon application of fluid pressure of selected magnitude.

In operation, bridge plug 605 according to the present invention is assembled into a workstring (not shown) at the surface of the wellbore (not shown) and is run into the wellbore to a desired location. At the desired location in the wellbore, bridge plug 605 may be set actuated or inflated into sealing engagement with the wellbore by the following procedure.

Pressurized fluid is pumped through workstring and enters bridge plug 605 through screen filter 607. Pressurized fluid flows from screen filter, fluid conduit 613a in connection tube 613, through fluid conduit 615a in fishing neck 615, through fluid conduit 617a of upper adapter 617, and into fluid conduit 621a of mandrel 621. Closure member 647b, 649, obstructs the fluid conduit in 621a in mandrel 621 so that fluid pressure may be increased inside mandrel 621. As fluid pressure increases, fluid flows through port 621b into a chamber defined between mandrel 621, upper adapter 617a, poppet housing 619, and poppet 623. Responsive to fluid pressure, poppet 623 moves relative to mandrel 621 and poppet housing 619 when the fluid pressure differential acting on poppet 623 exceeds the biasing force of biasing member 625. As poppet 623 moves relative to poppet housing 619, poppet 623 moves past a shoulder 619a formed in the interior wall of poppet housing 619, wherein pressurized fluid is permitted to flow around poppet 623 and poppet seal member 623a. Fluid continues to flow between the exterior of mandrel 621 and inflatable packing element 633 to inflate inflatable packing member 629.

Inflation of inflatable packing element 633 will cause shear member 645 in lower housing 643 to fail, thereby permitting relative movement between mandrel 621 and lower packing element assembly (which includes lower element ring 635, wedge ring 637, lower element adapter 639, and lower housing 643). Inflation of inflatable packer element 633 and relative movement between the lower element assembly and mandrel 621 permits inflatable packing element 633 to extend generally

radially outwardly from mandrel 621 and into sealing engagement with a sidewall of the wellbore

After sealing engagement is obtained, fluid pressure within mandrel 621 may be reduced, which permits biasing member 625 to return poppet 623 to its original position, blocking fluid flow out of the inflation region defined between mandrel 621 and inflatable packing element 631.

Bridge plug 605 described herein is arranged as a permanent bridge plug. Permanent bridge plugs, once set or inflated, cannot be deflated or unset and removed from the wellbore. It is within the scope of the present invention, however, to provide a retrievable bridge plug, which may be selectively inflated and deflated and removed from or repositioned in the wellbore. Such a retrievable bridge plug may be obtained by provision of conventional deflation means to permit selective inflation and deflation of the retrievable bridge plug. Bridge plug 605 provides a drainage passage 621a, in fluid communication with drainage sand (331 in Figure 6) through sand screen 607, and in communication with an exhaust member (guide shoe 649) to provide drainage of fluid from the plug member.

With reference now to Figures 1 through 9e, the operation of the apparatus will be described. The following description is of a through-tubing formation fracturing operation. However, the apparatus is not limited in utility to either through-tubing operations or fracturing and other secondary operations.

As a preliminary step, workstring 3 is prepared at the surface with a terminal end or sub adapted for delivering and setting a partition or obstruction member, preferably inflatable packer 5, 605. Partition or obstruction member 5, 605 need not, however, be inflatable packer 5, 605, but could be any sort of wellbore tool adapted to selectively and at least partially obstruct wellbore 1.

Workstring 3 then is run into wellbore 1 to a selected depth or location therein. As illustrated in Figures 1 and 8, the selected depth or location in wellbore 1

may be a point between sets of perforations 13, 15, wherein it is advantageous to separate and isolate a first wellbore region or zone proximal to one set of perforations 13 from a second region or zone proximal to a second set of perforations 15. At the selected depth or location in wellbore 1, partition or obstruction member 5, 605 is set and released from workstring 3 in a conventional manner.

For through-tubing operations, it is advantageous that workstring 3 and partition or obstruction member 5, 605 have outer diameters that are as small as possible to facilitate movement of workstring 3 and partition or obstruction member 5, 605 through reduced-diameter production tubing or otherwise obstructed wellbore sections.

An inflatable packer 5, 605 is provided with an elongate screen filter assembly 7, 607, which is in fluid flow communication with a fluid exhaust assembly 9, 647 to provide fluid drainage. Preferably with such an inflatable packer, a slurry of drainage or filter sand is (331 in **Figure 6**) deposited adjacent to inflatable packer 5, 605 in a quantity sufficient to fully encase or enclose screen filter member assembly 7, 607. Such a column of drainage sand provides a pre-filter for the screen filter assembly 7, 607, preventing abrasive fines from entering inflatable packer 5, 605 and tending to cause premature mechanical failure of inflatable packer 5, 605. A preferred drainage sand column (331 in **Figure 6**) is formed of coarse, 20/40 mesh, silica sand that is pumped into wellbore 11 in a fluid slurry with ordinary fresh water as the slurry fluid.

After partition or obstruction member 5, 605 is set and released, at least partially obstructing wellbore 1, aggregate mixture is prepared at the surface into a fluid slurry. Preferably, the aggregate mixture comprises 60% by weight coarse, 20/40 mesh, silica sand, 20% by weight intermediate, 100 mesh, silica sand, 15% by weight fine, 200 mesh, silica sand, and 5% by weight bentonite or bentonitic material. Preferably, fresh water is used as the slurry fluid to hydrate and disperse bentonitic particles into a colloidal form. The slurry should be sufficiently agitated to ensure dispersion of the bentonitic material.

The aggregate mixture slurry then is pumped through workstring 3 and into wellbore 1 adjacent and atop the drainage sand column. After a sufficient volume of aggregate mixture fluids slurry (a quantity sufficient to produce a column at least 30cm (12") in height) is pumped into wellbore 1, pumping should cease. A period of time, preferably greater than five to ten minutes, should elapse to permit the aggregate mixture fluid slurry to settle to a relatively quiescent condition.

After the settling period has elapsed, fracturing operations may be commenced. In a typical fracturing operation, conventional fracturing fluid (17 in **Figure 1** and **317** in **Figure 6**) is pumped through workstring **3** into wellbore **1** at a volume flow rate sufficient to achieve the necessary fluid pressure for successful fracturing (typically approaching 70 x 10^5 kg/m^2 (10,000 psi)). As fluid pressure increases, the axial force exerted by fluid pressure on plug member 11, 211, 311 increases. The increased axial force on plug member **11, 211, 311** compacts plug member **11, 211, 311** and causes drainage of gross water from the aggregate mixture fluid slurry, through drainage sand and drain filter assembly **7, 607,** wherein the gross water is exhausted through fluid exhaust assembly below inflatable packer **5, 605.** Gross water is fluid contained in the pores or interstitial spaces between sand grains in the aggregate mixture. Gross water is to be distinguished from hydrated water, which comprises small quantities of water that is hydrated or bonded to bentonitic particles. It is extremely advantageous to drain gross water from plug member **11, 211, 311**, so that the aggregate mixture can be compacted to a strong, substantially solid and substantially fluid-impermeable plug member **11, 211, 311.** Hydrated water is desirable because it maintains bentonitic particles in the hydrated or swelled form, which tends to reduce the fluid permeability of plug member 11, 211, 311.

Thus, a preferred plug member 11, 211, 311 will possess two regions of differing permeability: a solid substantially fluid-impermeable, force transferring region; and a relatively fluid-permeable drainage sand region. Screen filter 7, 607 of inflatable packer 5, 605 permits drainage of gross water from plug member 11, 211, 311 yet prevents significant quantities of the aggregate mixture of plug member 11, 211, 311 or drainage sand 331 from being carried away with the gross water.

As fluid pressure is increased, plug member 11, 211, 311 is compressed and compacted and becomes more substantially fluid-impermeable and stronger. It is believed that plug member 11, 211, 311 employs a "slip-stick" deformation mechanism, which improves the strength and substantial fluid impermeability of plug member 11, 211, 311. It is believed that the combination of coarse, intermediate, and fine sand particles, along with the ultra-fine, hydrated, bentonitic particles, permits plug member 11, 211, 311 to deform continuously as axial forces exerted thereon vary. This continuous deformation, called the slip-stick mechanism, permits plug member 11, 211, 311 to compact into a strong and substantially fluid-impermeable plug that continuously redistributes stresses within itself, thereby avoiding disintegration and failure. During the fracturing operation, the slip-stick mechanism of the aggregate material of plug member 11, 211, 311 permits plug member 11, 211, 311 to seal against fluid pressure loss, and to transfer axial loads, which otherwise would be exerted directly on inflatable packer 5, 605, to wellbore 1, which can more easily bear such extreme loads. Fluid drainage must be provided to permit the aggregate mixture to compact tightly and to achieve the slip-stick deformation mechanism, which cannot be achieved if the content of gross water in the aggregate mixture is excessive.

It should be noted that force transfer away from partition or obstruction member 5, 605 is sufficiently substantial that partition member 5, 605 may be unset or deflated, and plug member 11, 211, 311 will maintain its strength and sealing integrity.

After fracturing operations are complete, plug member 11, 211, 311 may be disintegrated, dissolved, or washed out (substantially as described with reference to Figure 8) by directing a high-pressure fluid stream 19 from workstring 3. The disintegrated fluid member and fluid may be circulated out of wellbore 1 or suctioned therefrom using a conventional wellbore tool.

Thus, the apparatus is operable in a plurality of modes of operation, the modes of operation including: a delivery mode of operation in which an aggregate mixture including particulate matter is conveyed into a wellbore in a fluid slurry form to a position adjacent a partition or obstruction member. Another mode of

operation is a compaction mode in which axial force from a source of axial force in the wellbore is applied to the aggregate mixture to compact the aggregate mixture and at least partially form a plug member. Yet another mode of operation is a force-transfer mode in which the plug member transfers force from the source of axial force away from the partition member into the wellbore. Still another mode of operation is a wash-out mode of in which the plug member is disintegrated by application of a stream of high-pressure fluid. Still another mode of operation is a communication mode in which the plug member is disintegrated and the partition member is removed from the wellbore thereby allowing fluid communication between first and second wellbore regions.

The apparatus has a number of advantages. One advantage is the provision of a strong, substantially fluid-impermeable means for sealing against fluid flow communication between a first and second regions in a wellbore. Another advantage is that the force-transfer characteristics of the plug member obviate the need for expensive high-pressure rated partition or obstruction members, such as inflatable packers or bridge plugs. Therefore, through-tubing operations and operations in otherwise obstructed wellbores are facilitated and rendered less costly. Still another advantage is that the plug member is formed easily and is disintegrated easily, permitting rapid and efficient workover or secondary recovery operations.

The particulate matter pressure plug may be utilized in completion operations in lieu of particular completion tools or processes, or in supplementation of particular wellbore tools and processes. Figures 10A through 10N are simplified schematic depictions of particular wellbore completion operations, and will be utilized to provide examples of how the particulate matter pressure plug may be utilized in completion operations.

During completion operations, a wellbore 1001 extends from a surface location and is defined by a borehole 1003 which extends downward through earth formations 1005. Most wellbores include a casing string 1007 which is secured in position relative to borehole 1003 by cement 1009. In some situations, all or a portion

of the casing string is secured in position relative to the borehole through utilization of external casing packers, such as external casing packer 1011 which is depicted schematically in Figure 10B The particulate matter pressure plug 1013 may be utilized in combination with cement 1009 and/or external casing packer 1011. In this particular configuration, which is shown in Figure 10B, the particulate matter pressure plug 1013 is utilized to transfer loads laterally from casing string 1007 to borehole 1003. Figure 10C depicts particulate matter pressure plug 1013 disposed between upper and lower intervals of cement 1015, 1017, and which facilitates the transfer of loads from casing string 1007 to formation 1005.

During completion operations, sections of radially reduced casing are suspended from larger diameter casing which is disposed above and secured in a fixed position relative to the borehole. This is shown schematically in the view of Figure 10D. As is shown, lower casing section 1021 is lowered through the central bore 1023 of upper casing section 1019, and secured in position relative to upper casing section 1019 by gripping and sealing assembly 1025, which is shown only schematically in this view. Figure 10E depicts how the particulate matter pressure plug of the present invention may be utilized with a gripping and sealing assembly 1025 in order to transfer loads laterally from lower casing section 1021 to upper casing section 1019, and to simultaneously seal the potential fluid flow path between upper casing section 1019 and lower casing section 1021.

As is shown in Figure 10E, particulate matter pressure plug 1029 may be provided in a position intermediate lower casing section 1021 and upper casing section 1019. In the view of Figure 10E particulate matter pressure plug 1029 is located intermediate metal-to-metal seal 1033 and gripping assembly 1027, both of which are depicted schematically to simplify the drawing. As is shown, particulate matter containment member 1031 is disposed beneath particulate matter pressure plug 1029 Particulate matter pressure plug 1029 operates to transfer load laterally from lower casing section 1021 to upper casing section 1019, in supplementation of the load transference which occurs through gripping assembly 1027. Additionally, particulate matter pressure plug 1029 may be utilized to seal the potential fluid flow

path between lower casing section **1021** and upper casing section **1019**, in supplementation of the metal-to-metal seal **1033**.

Typically, during completion operations, a workstring (or alternatively a production tubing string) is lowered within the casing string to a desired location. The workstring typically includes one or more perforating guns, one or more valves, and one or more packers, which cooperate to allow for the selective perforation and testing of particular formations. In general terms, the packers are utilized to isolate an annular region between the workstring and the casing string in a region of interest. The perforating gun or guns are utilized to perforate a particular section or sections of the casing string to allow the flow of fluids such as formation water, oil, and gas from the formation into the annular region. The fluids are allowed to pass through one or more valves into the workstring, where they are drawn to the surface and analyzed. Subsequent to the well testing operations, a production tubing string is lowered into position within the casing string, and packers are set to centralize, stabilize, and locate the production tubing string relative to the casing string, as well as to seal particular annular regions.. Then one or more valves are open to allow production of the fluid from the annular region to the central bore of the production tubing string. These operations are shown collectively and schematically in **Figure 10F**. As is shown, a workstring or production tubing string **1037** is lowered within casing string which is composed of upper casing section **1019** and lower casing section **1021**. The workstring of production tubing string includes a packer **1039**, a valve **1041**, and a perforating gun **1043**, all of which are depicted schematically.

In **Figure 10G**, production tubing string **1037** is shown in a fixed position relative to casing string **1045**, with packer **1043** set to locate, stabilize, and seal, as is conventional. As is shown perforations **1047** allow the inward flow of hydrocarbons and formation water, which are produced through valve assembly **1049** and lifted to the earth's surface utilizing either gas lift technology, sucker rod pumping devices, or submersible pumps, none of which are shown in this figure for purposes of simplicity and clarity. As is shown in **Figure 10H**, a particulate matter pressure plug **1051** may be provided atop and adjacent to packer **1043** to supplement the transference and sealing action of packer **1043**.

During certain operations, it is desirable to plug temporarily or permanently a tubular conduit, such as production tubing string **1037** of **Figure 10I**. As is shown, a temporary plug **1053** is located in the central bore of production tubing string **1037**. The particulate matter pressure plug **1055** of the present invention may be provided above and adjacent the temporary or permanent plug to bolster the pressure differential which can be accommodated by plug **1053**, and to supplement the sealing action of plug **1053**. **Figure 10J** shows an alternative use of the particulate matter pressure plug to bolster the load bearing and sealing action of bridge plug **1057**. As is shown, particulate matter pressure plugs **1058**, **1059** are located adjacent bridge plug **1057**, and operates to increase the sealing and load transference capabilities of bridge plug **1057**. In the view of **Figure 10K**, particulate matter pressure plug **1061** is shown located adjacent annulus safety valve **1063**, and may be utilized to bolster the sealing capability of annulus safety valve of **1063**.

Figure 10L depicts the utilization of the particulate matter pressure plug of the present invention to seal leaks within the tubular conduit, such as tubing string **1071**. As is shown, a partition member **1069** is located adjacent leak **1065** and the particulate matter and binder is located there above and adjacent to leak **1065**. The particulate matter pressure plug is utilized in this configuration primarily as a sealing device, and can obviate expensive workover operations which would ordinarily require the pulling of production tubing string **1071** in order to repair leak **1065**.

The particulate matter pressure plug of the present invention may also be used in flow control and gravel packing operations, as is depicted schematically in **Figures 10M** and **10N**. **Figure 10M** schematically depicts a completed wellbore **1081** with production tubing **1083** disposed therein. A plurality of perforations **1085** are provided to allow the flow of hydrocarbons into the wellbore. The production tubing string **1083** includes a gravel pack screen **1087** which allows wellbore fluids to flow into the production tubing string, but which prevents the flow of gravel pack material **1093** (such as sand, glass beads, or other particulate matter such as gravel) which has been intentionally placed into the wellbore and surrounding formation to check the

inward flow of fine particulate matter such as sand, and to prevent the collapse or deterioration of the wellbore while the well is being produced.

The pressure particulate matter pressure plug **1089** of the present invention may be located in a predetermined position within the gravel pack to prevent or limit the flow of fluids between particular portions of the wellbore. If a complete restriction is desired, then the particulate matter is compacted sufficiently to form a fluid impermeable barrier; however, if a mere flow restriction is required, then the particulate matter is compacted to a lesser extend to allow for some limited flow through particulate matter pressure plug **1089**. This technique is particularly useful when subsurface formations have differing pressure and production characteristics. The particulate matter pressure plug may be utilized to restrict or block flow between formations which have greatly differing pressures, for example. A plurality of the particulate matter pressure plugs may be located throughout the gravel pack to obtain particular flow and production goals.

Another utilization of the particulate matter pressure plug of the present invention is to obtain a flow objective. As is shown in **Figure 10N**, production tubing string **1084** extends downward within **1082**. A plurality of perforations **1088** are provided to allow the flow of wellbore fluids into the annular region. Production tubing string includes production valve **1086** which allows for the inward flow of wellbore fluids. As is shown in **Figure 10N**, the annular region between production tubing string and wellbore **1082** is gravel packed with particulate matter. As is shown, particulate matter pressure plug **1094** is provided to block or restrict the flow of fluids between annular regions **1090** and **1092**. A second particulate matter pressure plug **1096** is provided to prevent or restrict the flow of wellbore fluids between annular regions **1092** and **1098**. This may be especially useful if the formations above or below valve **1086** are low pressure zones, region of the wellbore surrounding valve **1086** is a high pressure zone. It may be beneficial to block the flow of fluids up and down the wellbore annulus in order to prevent a net loss of pressure from a high-pressure zone to a lower pressure zone.

The method of forming the plug includes three broad method steps The first step is to convey a quantity of particulate matter to a particular wellbore location. Then, the particulate matter is contained at least temporarily in order to allow compaction. The third step is compaction and dehydration of the particulate matter in a manner which generates the useful force transference and sealing of the present invention. A variety of alternatives exists for the conveyance, containment, and compaction operations, each of which will be discussed herebelow. **Figures 11A** through **11I** schematically depict a variety of conveyance and containment options available for the particulate matter pressure plug of the present invention.

First with reference to **Figure 11A**, a dump bailer **1101** may be utilized to dump the particulate matter in a wellbore fluid column either remotely from or adjacent a containment member **1105** in order to allow for the aggregation of particulate matter **1103** and formation of the particulate matter pressure plug of the present invention, preferably through application of force through a fluid column, but not necessarily so. **Figure 11B** depicts the utilization of a pump **1107** which directs a slurry including the particulate matter through a wellbore conduit **1109** (such as a production tubing string) and a valve **1111** to locate particulate matter **1113** adjacent containment barrier **1115**. In **Figure 11C**, the utilization of a coiled tubing string **1117** is depicted to locate particulate matter **1119** adjacent a wellbore barrier or containment member. In **Figure 11D**, an electrical wireline **1121** is depicted energizing an electrically actuable pumping and dumping device **1123** which deposits particulate matter **1125** adjacent a containment barrier in order to form the particulate matter pressure plug of the present invention. **Figure 11E** depicts the utilization of a hydraulic control line **1127** to deposit particulate matter **1129** adjacent a wellbore barrier such as safety valve **1131**. **Figure 11F** depicts the utilization of an offshore umbilical **1133** to deposit particulate matter below subsurface wellhead **1135** to locate particulate matter **1139** in a subsurface conduit **1137** adjacent a containment barrier or member. Figure **11G** depicts the utilization of an elastomeric balloon-type conveyance device which loaded with particulate matter weighted, and dropped within a wellbore fluid column where it eventually ruptures and deposits the particulate matter adjacent a containment barrier **1145** in a particular location **1143**. **Figure 11H**

schematically depicts the utilization of a fluid-permeable sack or containment **1147** which is loaded with particulate matter and a binder, and which is pumped down or gravity-driven downward within a particular fluid column to be located adjacent a containment barrier member **1149** Figure **11I** depicts utilization of a mesh or wire basket **1151** which may be filled with particulate matter and lowered to a particular location within a wellbore for formation of the pressure plug of the present invention. **Figure 11J** is a perspective view of one type of wire mesh basket.

As is shown, in this particular embodiment, the basket is cylindrical in shape, and includes a central bore **1161** which allows the basket to ride to a particular location along the exterior surface of a particular wellbore conduit. Preferably, the basket is formed of a wire having a mesh size which is sufficient to contain all or most of the particulate matter which is loaded therein. Force is applied to the particulate matter through the wire mesh container by application of a high pressure fluid column thereto in order to form a load transferring and sealing particulate matter pressure plug.

Figures 11K and **11L** depict two alternative techniques for compacting and dehydrating the particulate matter pressure plug of the present invention. **Figure 11K** depicts the utilization of an axial loading device which perceives an axial load and applies it through piston head **1173** to particulate matter **1175** to compress it against containment member **1177**. An alternative technique is depicted in **Figure 11L**. This technique involves the initiation of a chemical reaction to generate gas from combustive or explosive material **1181**, which acts on movable piston component **1183** which is urged downward to compress particulate matter **1185** against containment member **1187**.

One significant advantage of the present invention is that the particulate matter pressure plug is substantially unaffected by high wellbore temperatures, unlike many wellbore tools which include elastomeric components and in particular wellbore tools which include elastomeric sealing components. The particulate matter pressure plug of the present invention may be used either in lieu of, or in support of, a conventional wellbore tool, and may be directly exposed to regions of the wellbore which are particularly high-temperature regions. The particulate matter pressure plug

of the present invention is also advantageous with respect to the prior art insofar as it is extremely low in cost. The particulate matter pressure plug of the present invention is further advantageous over the prior art in that it is easy to locate and remove the particulate matter as compared to mechanical wellbore tools which are difficult to repair or replace.

While the invention has been shown in only one of its forms, it is not thus limited, but is susceptible to various changes and modifications without departing from the scope thereof.

CLAIMS:

1. A method of forming a pressure plug in a wellbore, comprising the method steps of:

forming a mixture of a plurality of types of particulate material;

depositing said mixture of said plurality of types of particulate material adjacent a selected wellbore structure utilising at least one of the following delivery mechanisms;

a) a coiled tubing string;

b) an electrically-actuated pump carried on a wire line;

c) a hydraulic control line; or

d) an offshore umbilical;

providing a containment member for locating said plurality of types of particulate matter, formed at least in part of:

a) an elastomeric bag;

b) a fluid-permeable sack

c) a mesh basket; or

d) a wire basket; and

compacting said plurality of types of particulate material into a plug by applying force thereto; and

draining fluid from at least a portion of said plug during at least compaction.

2. A method of transferring axial force in a wellbore from a fluid column to a wellbore surface, comprising the method steps of:

delivering a mass of particulate material to a particular location in said wellbore utilising at least one of the following delivery mechanisms:

a) a coiled tubing string;

b) an electrically-actuated pump carried on a wireline;

c) a hydraulic control line; or

d) an offshore umbilical;

providing a containment member for locating said particulate matter at said location formed at least in part of:

a) an elastomeric bag;

b) a fluid-permeable sack

c) a mesh basket; or

d) a wire basket; and

applying said axial force from said fluid column to said mass of particulate material causing mechanical compaction and partial draining of said mass of particulate material and reducing fluid permeability of said mass of particulate material; and

transferring through said mass of particulate material a selected amount of axial force to said wellbore surface.

3. A method of transferring axial force according to claim 2, further comprising:

reversibly binding said mass of particulate material together with a binding component.

4. A method of transferring axial force according to claim 3, further comprising:

filling interstitial spaces in said mass of particulate material with said binding component.

5. A method of transferring axial force according to claim 2, further comprising:

filling interstitial spaces in said mass of particulate material with a hydrating component.

6. A method of transferring axial force according to claim 2, further comprising:

removing said mass of particulate material from said wellbore by applying a high pressure fluid stream thereto.

7. A method of transferring axial force according to claim 2, further comprising:

disintegrating said mass of particulate material by applying a removal fluid thereto; and

removing said mass of particulate material, in slurry form, from said wellbore.

8. The method of transferring axial force according to claim 2, further comprising:

removing fluid from said mass of particulate material during compaction.

9. A method of transferring loads in a wellbore, comprising the method steps of:

conveying a quantity of particulate matter of differing particulate sizes to a predetermined wellbore location utilizing at least one of the following delivery mechanisms:

a) a coiled tubing string;

b) an electrically-actuated pump carried on a wirline;

c) a hydraulic control line; or

d) an offshore umbilical;

containing said particulate matter in a containment member formed at least in part of:

a) an elastomeric bag;

b) a fluid-permeable sack

c) a mesh basket; or

d) a wire basket; and

compacting said particulate matter;

utilising said particulate matter to transfer

laterally a preselected amount of force in said wellbore.

10. A method of transferring loads according to claim 9, further including:

dehydrating at least a portion of said particulate matter; and

sealing a flow path in said wellbore with said particulate matter.

11. A method of completing an oil and gas wellbore, comprising the method steps of:

providing a tubular string;

providing a plurality of completion tools;

locating selected ones of said plurality of completion tools in preselected locations on said tubular string;

lowering said tubular string into said wellbore,

utilising selected ones of said plurality of completion tools to perform at least one of (1) fluid flow paths within said wellbore;

conveying a quantity of particulate matter of differing particulate size to a predetermined wellbore location;

at least temporarily containing said quantity of particulate matter at a predetermined wellbore location in a containment member formed at least in part of:

a) an elastomeric bag;

b) a fluid-permeable sack

c) a mesh basket; or

d) a wire basket; and

compacting said quantity of particulate matter;

utilizing said quantity of particulate matter to perform at least one of (1) transfer load within said

wellbore, and (2) seal fluid flow paths within said wellbore;

wherein said particulate matter is utilised to perform at least one of the following operations:

1) to supplement the action of cement to transfer loads from tubulars within said wellbore formation surrounding said wellbore;

2) to form a seal in said liner hanger assembly;

3) to seal a leak in a particular wellbore tubular;

4) to secure a gravel pack assembly in place;

5) to co-operate with a gravel pack assembly to control fluid flow;

6) to isolate a zone by sealing above and below the zone.

12. A method of completing an oil and gas wellbore, according to claim 11 wherein said quantity of particulate matter is conveyed within said wellbore utilising at least one of:

(1) gravity;

(2) a fluid pump;

(3) coiled tubing;

(4) an electric line delivery mechanism;

(5) a control line; and

(6) an umbilical.

13. A method of completing an oil and gas wellbore, according to claim 11 wherein said quantity of particulate matter is contained utilising at least one of:

(1) a fluid permeable membrane;

(2) a rupturable container; and

(3) a mesh housing.

Amendments to the claims have been filed as follows

1. A method of forming a pressure plug in a wellbore, comprising the method steps of:

forming a mixture of a plurality of types of particulate material;

depositing said mixture of said plurality of types of particulate material adjacent a selected wellbore structure utilising at least one of the following delivery mechanisms;

a) a coiled tubing string;

b) an electrically-actuated pump carried on a wireline;

c) a hydraulic control line; or

d) an offshore umbilical;

compacting said plurality of types of particulate material into a plug by applying force thereto; and

draining fluid from at least a portion of said plug during at least compaction.

2. A method of transferring axial force in a wellbore from a fluid column to a wellbore surface, comprising the method steps of:

delivering a mass of particulate material to a particular location in said wellbore utilising at least one of the following delivery mechanisms:

a) a coiled tubing string;

b) an electrically-actuated pump carried on a wireline;

c) a hydraulic control line; or

d) an offshore umbilical;

applying said axial force from said fluid column to said mass of particulate material causing mechanical compaction and partial draining of said

mass of particulate material and reducing fluid permeability of said mass of particulate material; and

transferring through said mass of particulate material a selected amount of axial force to said wellbore surface.

3. A method of transferring axial force according to claim 2, further comprising:

reversibly binding said mass of particulate material together with a binding component.

4. A method of transferring axial force according to claim 3, further comprising:

filling interstitial spaces in said mass of particulate material with said binding component.

5. A method of transferring axial force according to claim 2, further comprising:

filling interstitial spaces in said mass of particulate material with a hydrating component.

6. A method of transferring axial force according to claim 2, further comprising:

removing said mass of particulate material from said wellbore by applying a high pressure fluid stream thereto.

7. A method of transferring axial force according to claim 2, further comprising:

disintegrating said mass of particulate material by applying a removal fluid thereto; and

removing said mass of particulate material, in slurry form, from said wellbore.

8. A method of transferring axial force according to claim 2, further comprising:

removing fluid from said mass of particulate material during compaction.

9. A method of transferring loads in a wellbore, comprising the method steps of:

conveying a quantity of particulate matter of differing particulate sizes to a predetermined wellbore location utilizing at least one of the following delivery mechanisms:

a) a coiled tubing string;

b) an electrically-actuated pump carried on a wireline;

c) a hydraulic control line; or

d) an offshore umbilical;

containing said particulate matter;

compacting said particulate matter;

utilising said particulate matter to transfer laterally a preselected amount of force in said wellbore.

10. A method of transferring loads according to claim 9, further including:

dehydrating at least a portion of said particulate matter; and

sealing a flow path in said wellbore with said particulate matter.

11. A method of completing an oil and gas wellbore, comprising the method steps of:

providing a tubular string;

providing a plurality of completion tools;

locating selected ones of said plurality of

completion tools in preselected locations on said tubular string;

lowering said tubular string into said wellbore,

utilising selected ones of said plurality of completion tools to perform at least one of (1) fluid flow paths within said wellbore;

conveying a quantity of particulate matter of differing particulate size to a predetermined wellbore location;

at least temporarily containing said quantity of particulate matter at a predetermined wellbore location;

compacting said quantity of particulate matter;

utilizing said quantity of particulate matter to perform at least one of (1) transfer load within said wellbore, and (2) seal fluid flow paths within said wellbore;

wherein said particulate matter is utilised to perform at least one of the following operations:

1) to supplement the action of cement to transfer loads from tubulars within said wellbore formation surrounding said wellbore;

2) to form a seal in said liner hanger assembly;

3) to seal a leak in a particular wellbore tubular;

4) to secure a gravel pack assembly in place;

5) to co-operate with a gravel pack assembly to control fluid flow;

6) to isolate a zone by sealing above and below the zone.

12. A method of completing an oil and gas wellbore, according to claim 11 wherein said quantity

of particulate matter is conveyed within said wellbore utilising at least one of:

(1) gravity;
(2) a fluid pump;
(3) coiled tubing;
(4) an electric line delivery mechanism;
(5) a control line; and
(6) an umbilical.

13. A method of completing an oil and gas wellbore, according to claim 11 wherein said quantity of particulate matter is contained utilising at least one of:

(1) a fluid permeable membrane;
(2) a rupturable container; and
(3) a mesh housing.

Application No: GB 9921717.6 **Examiner:** R L Williams
Claims searched: 1-13 **Date of search:** 12 October 1999

Patents Act 1977
Search Report under Section 17

Databases searched:

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK Cl (Ed.Q): E1F (FJT)(FJU)(FKA)

Int Cl (Ed.6): E21B 33/134,33/127,33/13,33/14,43/10,43/12,43/14

Other: EPODOC,WPI,JAPIO

Documents considered to be relevant:

Category	Identity of document and relevant passage	Relevant to claims
	Nothing relevant found	

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.